Service Date: April 28, 1994

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER Of The Application)	UTILITY DIVISION
Of The MONTANA POWER COMPANY For)	DOCKET No. 93.6.24
Authority To Increase Rates For)	ORDER No. 5709d
Natural Gas And Electric Service.)	(REVENUE REQUIREMENT)

* * * * *

FINAL ORDER

TABLE OF CONTENTS

APPEARANCES

FOR THE APPLICANT:

Marjorie L. Thomas, Esq., and Susan Callaghan, Esq., Montana Power Company, 40 East Broadway, Butte, Montana 59701

FOR THE MONTANA CONSUMER COUNSEL:

Robert A. Nelson, Esq., and Mary Wright, Esq., Montana Consumer Counsel, 34 West Sixth Avenue, P.O. Box 201703, Helena, Montana 59620-1703

FOR THE INTERVENORS:

Donald D. MacIntyre, Chief Legal Counsel, Department of Natural Resources and Conservation, Lee Metcalf Building, 1520 East Sixth Avenue, P.O. Box 202301, Helena, Montana 59620-2301, appearing on behalf of the DNRC

Deborah S. Smith, Esq., 1101 State Street, Helena, Montana 59601, appearing on behalf of District XI Human Resource Council, Montana Environmental Information Center, and Natural Resources Defense Council

Robert M. Pomeroy, Jr., Esq., Holland and Hart, 4601 DTC Blvd., Suite 1050, Denver, Colorado, 80237, appearing on behalf of the Large Customer Group

Donald W. Quander, Esq., Holland and Hart, 175 North 27th Street, Suite 1400, Billings, Montana, 50101-2048, appearing on behalf of the Large Customer Group

FOR THE COMMISSION:

Denise Peterson, Staff Attorney
Dan Elliott, Administrator
Eric Eck, Chief, Revenue Requirements Bureau
Sandra Barrows, Rate Analyst, Revenue Requirements Bureau
G. Joel Tierney, Rate Analyst, Revenue Requirements Bureau
Ron Woods, Rate Analyst, Revenue Requirements Bureau
William A. Rosquist, Rate Analyst, Rate Design Bureau
1701 Prospect Avenue, P.O. Box 202601, Helena, Montana

BEFORE:

Bob Anderson, Chairman
Bob Rowe, Vice Chairman
Dave Fisher, Commissioner
Nancy McCaffree, Commissioner
Danny Oberg, Commissioner

FINDINGS OF FACT
BACKGROUND

1. On June 21, 1993, the Montana Public Service Commission (Commission) received an application from the Montana Power Company (MPC or Company) for authority to increase electric and gas rates. At the time of the application MPC sought to raise electric rates to recover an additional $36,198,499 in annual revenues and to raise natural gas rates to recover an additional $10,264,608 in annual revenues. The initial proposed increases represented a uniform percentage change in rates of 11.36 percent for electric retail customers and an overall change of 10.73 percent for natural gas customers. MPC's application did not contain allocated cost-of-service studies nor proposed adjustments to its electric and natural gas rate structures. MPC indicated that it expected to make separate cost-of-service/rate design filings by July 30, 1993, for electric and after September 1, 1993, for gas.

2. Concurrent with its general rate increase application, MPC requested interim increases of $20,966,813 for the electric utility and $8,119,994 for the gas portion of the utility.

3. On June 23, 1993, the Commission issued a Notice of Application and Intervention Deadline and Procedural Order No. 5709a. The Commission established a procedural schedule setting December 14, 1993, as the opening day of the hearing. The Order also stated that the Commission had modified the previous procedural policy. The new policy prescribes the issuance of a final procedural order upon receipt of a rate increase application and delegates to the Commission staff the duty to set the procedural schedule and issue the Order without a prehearing conference.

4. On June 30, 1993, the Commission staff issued a Notice of Change of Hearing Date and Deadline for Service List. The notice modified the procedural schedule to change the hearing date from December 14, 1993, to December 7, 1993, and set July 13, 1993, as the deadline for becoming an "Interested Party" in this Docket.

5. On July 28, 1993, the Commission staff granted intervention in this Docket to the following:

Montana Consumer Counsel

Shelby Gas Association
Great Falls Gas Company
Department of Natural Resources and Conservation
Department of Social and Rehabilitation Services
District XI Human Resource Council
Rhone-Poulenc Basic Chemicals Company
Northern Plains Resource Council
U.S. Executive Agencies
Natural Resource Defense Council
Large Customer Group
Montana Irrigators, Inc.
Montana Environmental Information Center
CELP/BGI

6. On August 2, 1993, the Commission directed MPC to withdraw its proposals for an industrial retention rate and low-income discount rate from this Docket and present them as part of the cost-of-service and rate design filing. Rhone-Poulenc Basic Chemicals Company filed a request to withdraw testimony concerning the industrial retention rate for Rhone-Poulenc on August 24, 1993, which the Commission approved on September 3, 1993.

7. On September 10, 1993, the Commission staff amended the procedural schedule in Order No. 5709a, adding September 21, 1993, as the final day for intervenor discovery to parties other than MPC.

8. On September 20, 1993, the Commission identified the additional issues in this Docket as follows: (1) Adjustment to decoupling mechanism to account for increased off-system sales revenue; (2) Energy Service Charge approach to the lost revenue problem; (3) Changes in risk and Cost of Capital resulting from Demand Side Management (DSM) and DSM Recovery; (4) Alternative DSM proposal; (5) IRS Examination of the Tax Basis of Colstrip Unit No. 4; (6) Bond Ratings; (7) Experimental Compressed Natural Gas Filling Station Rate; (8) Gain on Disposition of Property Dedicated to Public Service; (9) Top Layer Coal Supply Blending for Colstrip Units 3 & 4; and (10) Efficiency of Headquarter Operations.

9. On October 15, 1993, the Commission denied late intervention to Paladin Associates.

10. On October 22, 1993, by Interim Order No. 5709b, the Commission authorized MPC an interim increase in annual Montana jurisdictional electric revenues of $8,825,155 and annual gas

revenues of $4,025,496.

11. On November 10, 1993, the Commission issued Order No. 5709c which amended the procedural schedule and rescheduled the hearing date to begin on January 18, 1994. The Commission issued a Notice of Public Hearing on December 17, 1993, also stating that separate "satellite hearings" may be scheduled at a later date.

12. The Commission duly issued and published Notice(s) of Public Satellite Hearing(s) scheduled for the following Montana towns and cities: Roundup, Red Lodge, Billings, Big Timber, Helena, Townsend, White Sulphur Springs, Great Falls, Shelby, Valier, Lewistown, Malta, Glasgow, Harlowton, Choteau, Big Sandy, Stanford, Havre, Superior, Thompson Falls, Hamilton, Missoula, Butte, Bozeman, Whitehall, Boulder and twice in White Sulphur Springs.

13. The following persons testified on revenue requirement issues in this Docket:

For MPC:	Robert P. Gannon	For MCC:	John W. Wilson
	Patrick R. Corcoran		Robert G. Towers
	David R. Houser		Caroline S. Wilson
	John S. Miller		Albert E. Clark
	Gene H. Wickes		David Kirby
	Perry J. Cole		Frank E. Buckley
	Charles E. Olson		
	Jerrold P. Pederson	For HRC:	Thomas M. Power
	John Landon		
	Mark Berkman	For LCG:	Katherine E. Iverson
	Jack Haffey		
	Thomas J. Matosich	For DNRC:	Lawrence P. Nordell
	Ernie J. Kindt		
	Ceil A. Orr	For MEIC:	Ken Toole
	William A. Pascoe		
	Daniel R. Reardon		

14. On January 12, 1994, the Commission staff issued its Prehearing Memorandum and Notice of Introduction of Discovery Responses.

15. This Docket addresses the revenue requirement of MPC. Cost-of-service/rate design issues are addressed separately in Docket No. 93.7.29.

RATE OF RETURN

16. On June 21, 1993, MPC witness Cole filed direct

testimony presenting MPC's proposed electric and natural gas capital structures and associated costs. Mr. Cole updated MPC's proposal in both his rebuttal testimony and again in December 1993 to reflect refinancing of pollution control revenue bonds (PCRB) and the issuance of preferred stock. A change in return on equity was also reflected based on the findings of Dr. Olson.

17. MPC proposed the following capital structure and associated costs:

Electric Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Long-Term Debt	$444,202	47.25%	7.67%	3.62%
Preferred Stock	81,109	8.63%	7.13%	0.62%
Common Equity	414,829	44.12%	12.25%	5.40%
Total	$940,140	100.00%		9.64%

Gas Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Long-Term Debt	$111,051	47.25%	8.51%	4.02%
Preferred Stock	20,277	8.63%	7.13%	0.62%
Common Equity	103,707	44.12%	12.25%	5.40%
Total	$235,035	100.00%		10.04%

(MPC Exh. 19, Updated PJC-13, pp. 1-2)

18. On September 7, 1993, MCC filed response testimony in this Docket. Dr. Caroline Wilson presented MCC's proposed electric and gas capital structures and associated costs. At the hearing Dr. Wilson updated those figures to reflect the refinancing completed by MPC. (Tr. pp. 444-445)

19. MCC proposed the following capital structure and associated capital costs:

Electric Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Long-Term Debt	$444,202	47.25%	7.67%	3.62%
Preferred Stock	81,109	8.63%	7.13%	0.62%
Common Equity	414,829	44.12%	10.25%	4.52%

Gas Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Total	$940,140	100.00%		8.76%
Long-Term Debt	$111,051	47.25%	8.51%	4.02%
Preferred Stock	20,277	8.63%	7.13%	0.62%
Common Equity	103,707	44.12%	10.25%	4.52%
Total	$235,035	100.00%		9.16%

(MCC Exh. 2a, Updated CSW-1)

Capital Structure

20. The capital structure is not a contested issue in this proceeding. The Commission accepts the capital structure proposed by the parties.

Cost of Capital

Long-Term Debt

21. The cost of long-term debt is not a contested issue in this proceeding as both MPC and MCC calculated a cost of 7.67 percent for the electric utility and 8.51 percent for the gas utility. These long-term debt costs are accepted by the Commission.

Preferred Stock

22. The cost of preferred stock is not a contested issue in this proceeding as both MPC and MCC calculated a cost of 7.13 percent. This cost of preferred stock is accepted by the Commission.

Common Equity

23. In his rebuttal testimony Mr. Cole requested an equity return of 12.25 percent, down from the originally requested 12.50 percent. Mr. Cole's requested equity return was based primarily on the testimony of Dr. Olson. Dr. Olson explained that the decrease in return was necessary to reflect the decline in interest rates and dividend yields that occurred since his initial testimony was prepared. (MPC Exh. 23, pp. 24-26)

24. Dr. Olson performed Discounted Cash Flow (DCF) analyses on 28 electric and 7 natural gas distribution utilities in deriving his recommended 12.25 percent return. In choosing comparable electric companies Dr. Olson included those electric

and combination companies with A or AA rated debt while excluding those with significant diversification and/or recent or expected dividend cuts. His comparable gas companies represent the Moody's Gas Distribution Group. Again, these are companies that have little diversification outside the gas distribution business.

25. The dividend yields in Dr. Olson's studies are calculated using the average of the high and low stock prices from March 1993 through August 1993 for each company and the indicated dividend at the end of the period. Dr. Olson then applied an adjustment factor to project the dividends forward into the upcoming year.

26. Dr. Olson's growth rates were determined by reviewing historical growth rates in earnings, dividends and book value, as well as analysts' projected growth rates. In addition, for electric he reviewed the market price growth rate and for gas the retention growth rate. Finally, the investor required return is multiplied by eight percent to reflect financing costs and potential market fluctuations. Dr. Olson's results are shown below:

	Electric		Gas	
Dividend yield	5.75	5.75	5.12	5.12
Yield adjustment	0.14	0.16	0.15	0.16
Expected growth	5.00	5.50	5.75	6.25
Investor required return	10.89	11.41	11.02	11.53
Adjusted Return	11.76	12.32	11.90	12.45

Based on this analysis, Dr. Olson recommended that MPC's electric utility be allowed to earn an equity return of 11.75 to 12.25 percent and that MPC's gas utility be allowed to earn an equity return of 12.0 to 12.5 percent.

27. To check the reasonableness of his DCF analysis, Dr. Olson conducted an interest premium analysis. The result of Dr. Olson's interest premium analysis was higher than his DCF results.

28. Dr. Wilson also used a DCF analysis in arriving at her return on equity recommendation. Dr. Wilson recommends an equity return for MPC's electric and gas utilities of 10.25 percent,

based on a recommended range for MPC of 10.0 to 10.50 percent. Dr. Wilson included 60 electric and combination utility companies in her DCF analysis. These companies represent most of the electric and combination electric and gas utilities reported in the Value Line Investment Survey. Several of the Value Line companies were not included because of data problems or dividend omissions or reductions. Dr. Wilson also relied upon restated 1992 earnings. She indicated that the very low level of earnings in 1992, apparently attributable to both economic conditions and unusual weather, understated investor's growth expectations.

29. Dr. Wilson's dividend yield of 6.1 percent reflects the average of the high and low stock prices for the six-month period ending June 1993 and the indicated dividend rate at the end of June. Dr. Wilson's dividend yield has not been increased to reflect increases during the first year following pricing. Rather, she takes this adjustment into account in her growth component.

30. To estimate the growth component, Dr. Wilson performed a statistical study using ten years of historical growth rates in earnings, dividends and book value for her 60 companies. The study measures the relationship between market prices and each of the 30 historical growth rates in order to estimate investors' expected growth rates. The results of the study indicate that growth expectations for the industry are in the 3.5 to 4.2 percent range. Dr. Wilson's adjustment for dividend growth subsequent to the pricing period results in a recommended industry growth rate of 3.7 to 4.3 percent.

31. Dr. Wilson's estimate of equity return requirements for the electric and combination utility industry is 9.8 to 10.4 percent. This result is the sum of the 6.1 percent yield and growth expectations in the 3.7 to 4.3 percent range.

32. Dr. Wilson estimates that investors require a return of 10.0 to 10.5 percent on MPC's common equity. In MPC Docket No. 88.6.15, Dr. Wilson determined that MPC's equity return requirement may have been 25 to 50 basis points higher than the industry. Taking into account the industry result in this Docket and the possibility of MPC's somewhat higher risk as compared to the industry, Dr. Wilson recommends an equity return for MPC of

10.25 percent.

33. Dr. Wilson also provided recent comparable earnings information for regulated electric and combination utility companies as well as for firms in the unregulated sector of the economy. She did not, however, recommend that MPC's return be set equal to that earned by the utility industry.

Commission Discussion

34. Dr. Olson and Dr. Wilson disagreed over the need for a flotation cost adjustment. Dr. Olson believes that a flotation cost adjustment must be reflected in all proceedings so that investors will stay whole in the event of future public offerings of stock. His adjustment is composed of two pieces. The first is a financing cost adjustment to cover issuance costs. The second adjustment provides protection in case stocks are issued in down markets. The flotation cost adjustment represents approximately 90 basis points. Dr. Wilson maintains that this adjustment is not necessary. The Commission agrees with Dr. Wilson. Dr. Olson's proposal would result in an annual recovery of total issuance costs for all outstanding common equity regardless of whether these costs were actually incurred. For example, the last time that MPC issued common shares of stock was in 1983. (MPC Exh. 2, Workpaper F, page 7 of 15) Clearly, if flotation costs had been allowed since 1983, MPC would have recovered, many times over, costs that were not incurred. Regarding protection from market conditions, the Commission agrees with Dr. Wilson:

> First of all, Dr. Olson's proposal to protect MPC's shareholders from unfavorable market conditions is one step in the direction of providing a guaranteed return to MPC, a measure to which utilities are not entitled. Second, judgement in the timing of issuing securities is one of the roles of management. Under current registration procedures, MPC has considerable freedom as to specific offering dates if any shares were going to be issued at all. The task of issuing new common stock at favorable market prices is a responsibility of MPC's management. There is no need for customers to pay rates sufficient to compensate MPC's shareholders in the event that management fails to meet that responsibility. (MCC Exh. 2, p. 40)

35. In his rebuttal testimony, Dr. Olson maintained that

Dr. Wilson's statistical model is very sensitive to minor changes in input data. He ran a multiple regression model to assess this sensitivity. Using Dr. Wilson's input data from Docket No. 90.6.39, Dr. Olson ran his model twice with slightly updated information. The model produced a different "most important" growth rate each time (i.e., the 2-year dividend growth rate in one instance and the 10-year earnings growth rate in an other compared to the 1-year dividend growth rate reported by Dr. Wilson). He concluded that the model is so sensitive that it is incorrect to use it for the purpose of estimating the cost of equity capital.

36. This is the same argument that Dr. Olson presented in Docket No. 90.6.39. The Commission found:

> The Commission believes that the updates in information would logically result in changes in the growth rates yielded by Dr. Smith's (name change to Dr. Wilson) statistical model. Common sense suggests that as information changes, so will the pricing patterns of investors. While Dr. Olson indicated that minor information updates resulted in different growth rates, he did not demonstrate that the magnitude of such changes was severe. To the contrary, he did not even report the actual growth rate figures that resulted from such updates. Therefore, the Commission finds little significance in Dr. Olson's conclusions relative to the sensitivity and usefulness of Dr. Smith's statistical model. (Order No. 5484k., FOF 57)

37. In this Docket, MCC asked Dr. Olson for the 2-year dividend growth rate and the 10-year earning growth rate that resulted from his model. (MCC DR Nos. 573, 574) Dr. Olson indicated that the magnitude of these growth rates was not given in his Docket No. 90.6.39 rebuttal testimony and that he had not saved the workpapers.

38. Dr. Olson relied on the results of his study to conclude that it was incorrect to use Dr. Wilson's model. However, the results of his study were not available in this Docket. The Commission questions the appropriateness of Dr. Olson relying on a study for which he cannot even provide results. The Commission again finds little significance in Dr. Olson's conclusions relative to the sensitivity and usefulness of Dr. Wilson's statistical model.

39. Dr. Wilson criticized Dr. Olson's use of the historical

growth rates in market price per share. She maintained that (1) the market price growth rate of 8.8 to 9.8 percent has occurred because stock market prices have advanced to extraordinary levels during the past decade; and (2) the opportunity for extraordinary price growth does not exist today. She concluded that absent inclusion of the price growth rates there is no support for Dr. Olson's 5.0 to 5.5 percent growth estimate.

40. The Commission is not persuaded by this argument. Had Dr. Olson relied solely on the market price growth rate, presumably he would have recommended a growth rate in the 8.8 to 9.8 percent range. Obviously market price growth was not the only information upon which Dr. Olson relied. Further, Dr. Wilson did not maintain that historical market price information is an inappropriate indicator to include in growth analysis, only that she does not believe the current results can continue. Dr. Wilson did not, however, indicate what price growth rate she thought would continue.

41. In his direct testimony, Dr. Olson reported that a recent Supreme Court decision implied that in estimating the return on equity, risks created by the specific regulatory system must be considered. (Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S.Ct. 609, 102 L.Ed.2d 646 (1989)) Mr. Cole, in his direct testimony, compared MPC's regulatory risks in Montana to those in other jurisdictions. After reviewing the treatment of trackers, the type of test year used, and the issue of preapproval, Mr. Cole concluded that MPC's risks are significantly higher than the average electric utility and comparable to the average gas utility.

42. When Mr. Cole reviewed MPC's financial performance he included both the Commission's adoption of optional filing rules and MPC's current proposal regarding the recovery of DSM-related lost revenue (both of which MPC expects to improve its financial position). However, he failed to mention either of these when assessing the risk in Montana.

43. Mr. Cole has not performed a thorough analysis of the risks facing MPC compared to risks in other jurisdictions. Further, he has not shown the quantitative impacts on capital costs these supposedly higher regulatory risks are creating.

Finally, regulatory risks are among other types of risks faced by utility companies. Risk analysis should include a comprehensive analysis of all major risks (regulatory or otherwise) facing the utility.

44. Mr. Cole discussed preapproval in terms of the Commission's "refusal" to preapprove resource additions. The Commission reminds Mr. Cole that the used and useful determination for utility assets included in rate base is prescribed by Montana Statute.

Return on Equity Conclusion

45. Both Dr. Wilson and Dr. Olson agree that judgment is required in determining the appropriate equity rate of return for a utility. The Commission finds credible several of the DCF judgments used by both parties in attempting to estimate MPC's cost of equity capital. Based on the information presented in this proceeding, the Commission finds that 11.0 percent is a reasonable cost of common equity capital for MPC's natural gas and electric utility. At 11.0 percent, MPC's allowed return is 110 basis points below the last Commission authorized equity return. Both parties acknowledge that money costs have fallen since MPC's last rate case and have agreed that the magnitude of the decline in MPC's common equity return requirement since Docket No. 90.6.39 was between 112 and 115 basis points. (Tr. pp. 452-453, MCC Exh. 3, pp. 8-9)

Overall Rate of Return

46. Based on the findings for capital structure, cost of debt, preferred stock and common equity, the Commission finds MPC's gas and electric utility overall rates of return to be 9.09 and 9.49 as demonstrated below:

Electric Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Long-Term Debt	$444,202	47.25%	7.67%	3.62%
Preferred Stock	81,109	8.63%	7.13%	0.62%
Common Equity	414,829	44.12%	11.00%	4.85%
Total	$940,140	100.00%		9.09%

Gas Utility	Amount (000)	Percent of Capitalization	Cost Rate	Rate of Return
Long-Term Debt	$111,051	47.25%	8.51%	4.02%
Preferred Stock	20,277	8.63%	7.13%	0.62%
Common Equity	103,707	44.12%	11.00%	4.85%
Total	$235,035	100.00%		9.49%

RATE BASE

Uncontested Issues

47. MPC and MCC agreed on a number of rate base issues in this Docket:
cash working capital (method), relocation reimbursements, future use gas wells and Shelby storage loss. The Commission accepts the positions agreed to by MPC and MCC.

Depreciation Reserve Adjustment

48. In its application filed June 21, 1993, MPC proposed using a year end 12/31/92 rate base. In prefiled direct testimony MPC established the original cost depreciated value of its rate bases at $243,556,167 and $944,885,487 for its gas and electric utilities, respectively. (MPC Exh. 33, Attachments DRR-3 and 4)

49. In prefiled direct testimony MCC witness Buckley proposed adjustments reducing MPC's proposed 12/31/92 rate bases by $8,920,451 and $39,938,318 for gas and electric respectively. (MCC Exh. 8, Attachment FEB-1) Mr. Buckley maintained that his adjustments reflect known and measurable changes that will occur during the allowed change period to the test year depreciation, depletion and amortization reserves (referred to as depreciation reserve).

50. MPC in rebuttal testimony filed October 18, 1993, opposed Mr. Buckley's adjustments to its proposed test year rate base calculation. MPC's witnesses Gannon, Haffey and Reardon argued that Mr. Buckley's proposed depreciation reserve adjustment violated ARM 38.5.606 (1)(d) which requires the rate base to be computed on an end of test year basis. The witnesses also testified that Mr. Buckley's proposed adjustment violated the ratemaking principle of matching.

51. MPC alternatively argued that if the Commission accepts

MCC's depreciation reserve adjustment, then MPC, for matching reasons, should be allowed to include used and useful post-test-year plant additions made through 12/31/93. In its rebuttal filing MPC updated its financial presentation through 12/31/93, with actual figures through 8/31/93 and MPC's projections through 12/31/93.

52. Mr. Buckley, in supplemental testimony, argued that MPC inappropriately used his depreciation adjustment as support for an argument that the rate bases of the utilities should be updated to include 1993 additions. Mr. Buckley stated in MCC Exhibit No. 9:

> These three witnesses and the Montana Power Company are still trying to establish a relationship between my adjustment and their proposed updates for 1993 additions. I must state once again that there is no relationship whatsoever between my adjustment and the proposed updates.
>
> My adjustment is only related to 1992 test year plant. This is plant which has been and can be identified, colored, marked and traced...clearly distinguishable.

53. MCC's witness relied on ARM 38.5.606 (1)(a), relating to known and measurable changes occurring within 13 months of the close of the test year, as support for his adjustment.
Mr. Buckley argued that his proposed adjustment to the 1992 test year depreciation reserve is a change that is known with certainty and measurable with reasonable accuracy and occurring within the allowed change period. Mr. Buckley also asserted that his adjustment provides a better match between investment and the revenues and expenses associated with the test year plant that will be in service during the rate effective period.

54. MPC presented a pro forma depreciation expense calculated using the 1992 test year values. This depreciation expense is the amount that will be charged to the accumulated depreciation reserve during the 13 month change period. MPC admitted that the proposed adjustment to the 1992 test year depreciation reserve is a change that is known with certainty, measurable with reasonable accuracy and occurring within the allowed change period. MPC maintained, however, that it would be

inappropriate to reduce rate base by this post-test-year expense. MPC asserted that the MCC proposal is unfair and violates the matching principle. The adjustment would capture the downward adjustment to test year rate base resulting from depreciation expense while ignoring additions and replacements made during the allowed change period which would increase rate base. The Commission agrees with MPC.

55. If the Commission allowed MCC's test year rate base reduction, a depreciation reserve adjustment that charges a full post-test-year of depreciation expense to the test year reserve account, then the utility should be allowed to include plant additions and replacements with proper matching. Commission recognition of the "return of" capital by ratepayers, while ignoring company-provided capital which the company is entitled to a "return of and on," when these are concurrent events, would violate the Commission's charge to balance the interests of the ratepayer and the company.

56. In this order the Commission must determine which of the proposed plant values, that is, 12/31/92, 8/31/93 or 12/31/93, is the most reasonable value to use in calculating the rate base for the rate effective period. Use of the 12/31/93 original cost plant values is wholly inappropriate. When the 12/31/93 plant value was presented to the Commission, the figures for September through December 1993 were projections. MPC alleged that the plant value projections were known changes that were measurable with reasonable accuracy. Therefore, MPC maintained that the Commission should accept the estimated 12/31/93 rate base if it accepts the depreciation reserve adjustment. MPC's assertion of the reasonable accuracy of its estimates, however, is not supported by the facts. The value of the actual plant additions for the period September through December 1993 were $7,650,557 more than MPC's estimated plant additions, or an overall error rate of 16 plus percent for the four month estimation period. This large an error rate over a four month period indicates that the known change was not measurable with reasonable accuracy. The Commission rejects MPC's proposal to use a 12/31/93 plant value.

57. The MCC in supplemental testimony agreed in principle

to use of an 8/31/93 closing date for MPC's original cost plant values. If the Commission accepted the updated actual financials of MPC, 8/31/93 would essentially become the new test year in the Docket. Proper annualized matching between MPC's depreciation expense and depreciation reserve would require recognition of 12 months of depreciation expense in the operating statement and the balance sheet for post-test-year plant additions. Under its accounting convention, MPC does not book depreciation expense until the year after plant is depreciated. As a result, there is no depreciation expense charged to the operating statement for post-test-year plant additions completed as of 8/31/93. To recognize 12 months of depreciation expense after the 8/31/93 closing date, the Commission would have to accept extension of the adjustment period through August, 1994.

58. For MPC to obtain a "return of and on" its post-test-year capital investment, the Commission would have to recognize an annualized depreciation expense as a cost. Under the MCC's depreciation reserve theory, extending the adjustment period to 8/31/94 in order to provide a "return of and on" post-test-year investment would require an extension of the adjustment period for depreciation expense on 12/31/92 test year plant to the same date.

59. Acceptance of the update through 8/31/93 would result in taking an additional eight months of depreciation expense to the 12/31/92 test year plant reserve. This allowance would extend the change period for the test year depreciation reserve from the 13 months allowed by the optional rules to 20 months. The Commission is unwilling to countenance such a dramatic departure from its allowed change period when the utility has not had an opportunity to have a "return of" a portion of the capital investment included in the test year reserve adjustment.

60. The Commission rejects the three proposed alternative plant values and finds that the plant value calculated pursuant to ARM 38.5.606 is reasonable, with an adjustment to accumulated depreciation to be discussed in the following findings. The 12/31/92 net plant value can be verified from the books and records of MPC and does not require extensive financial updating to achieve proper matching, as do the alternative proposals.

Further, the reasonableness of using the 12/31/92 plant value calculated by MPC is supported by the exhibits in this Docket.

61. Previously the Commission grappled with the issue of this proposed depreciation reserve adjustment in Mountain Water Company Docket No. 92.4.19. On reconsideration, the Commission reversed its decision to allow the adjustment. The Commission stated in Order No. 5625c, Finding of Fact (FOF) 24, that the record in Docket No. 92.4.19 did not support a departure from traditional ratemaking. The utility had not received notice from the Commission of its willingness to consider the post-test-year adjustment to the rate base, along with post-test-year plant additions, with matching revenues and expenses. As the Commission stated, "The proper course of action would have been to develop fully the issues of matching, rate base adjustments, test year determinations and fairness to both the utility and the consumers at the outset of the proceedings." (Id., FOF 25) The Commission promised to consider the merits of the adjustment and make a policy determination in MPC Docket No. 93.6.24 (present matter) with a fully developed record. (Docket No. 92.4.19, FOF 25)

62. MPC filed based on a 12/31/92 test year, with accumulated depreciation through 1992. In developing their positions, the record and decision alternatives in this Docket, parties moved the test year figures forward. To match the plant in service on 12/31/93, the Commission finds that it must have actual figures for 1993 plant additions and replacements, not estimates. MPC's belated attempt to introduce into evidence at the hearing the actual figures for 12/31/93 only presented due process problems, as intervenors had no opportunity to do discovery on the figures at that time. MCC was agreeable to use of 8/31/93 actual plant figures, with matching, for the Commission's consideration, provided that a full year's accumulated depreciation would be added to the reserve for 1992. The Commission finds mismatching would occur between the calculated 12/31/93 accumulated depreciation and the 8/31/93 plant, similar to but not as aggravated as the mismatch between 12/31/92 plant and 12/31/93 reserve.

63. The depreciation expense, unlike most expenses, affects

the balance sheet, as an adjustment to rate base in the formula of original cost minus accumulated depreciation. Depreciation expense is a non-cash item included in the operating statement for the purpose of recognizing the investor's entitlement to capital recovery over time. Since depreciation is a capital recovery mechanism, it affects the balance sheet. Capital recovery and capital investment are financial events that must be considered concurrently for an accounting period. The amount of capital recovered through depreciation expense wholly depends on the magnitude of capital investment as measured at any point in time. Capital recovery and investment are ongoing in nature. Choosing a point in time to measure the value of plant in service will never produce a perfect match. However, the Commission's choice of a test year end 12/31/92 plant value comes as close as is reasonably possible, because depreciation expense and plant are as recorded on the books and records of the utility.

64. The record in this case illustrates the need to follow traditional ratemaking practice, for practical reasons. The Commission and the parties experienced delay in processing this case with the updates and required further discovery, creating a moving target for the test year. The actual figures for 8/31/93 were the latest available prior to hearing, but there were still matching problems between the actual plant figures and the pro forma depreciation reserve. With a record and an array of choices, the Commission determines, as a matter of policy, that to make a decision other than this one on the depreciation reserve adjustment would unduly complicate and delay rate case proceedings.

Accumulated Depreciation

65. In prefiled direct testimony MCC witness Clark proposed reducing MPC's gas and electric 12/31/92 rate bases by $373,708 and $1,842,482, respectively, by crediting these amounts to accumulated depreciation. Mr. Clark stated that on its pro forma income statement MPC has reflected an annualized depreciation expense. However, MPC makes no adjustment to the rate base to reflect the impact of the expense adjustment. Mr. Clark asserted that both components require annualization for proper matching of the depreciation expense and investment associated with that

expense.

66. In rebuttal testimony Mr. Reardon cited two reasons for taking exception to Mr. Clark's proposed annualization adjustment. First, Mr. Reardon stated that the proposed depreciation reserve adjustment would flow the test period depreciation expense to accumulated depreciation, which would result in twice crediting Mr. Clark's adjustment to accumulated depreciation. Second, Mr. Reardon argued that Mr. Clark's adjustment includes depreciation expense in the accumulated depreciation account extending beyond the close of the test year.

67. In supplemental testimony Mr. Clark agreed with MPC that his proposed adjustment was duplicative, if Mr. Buckley's proposed adjustment is accepted. During the hearing, however, Mr. Clark stated that if the Commission rejects Mr. Buckley's proposed adjustment as it has since done in this order, then the Commission should make this annualization adjustment to the accumulated depreciation account.

68. The Commission agrees with Mr. Clark that this reduction to MPC's rate base is appropriate. MPC has presented a pro forma depreciation expense calculated using the 1992 test year plant value as its basis. This pro forma expense included in the operating statement is an increase over the actual amount charged during 1992. The difference between the pro forma expense and the actual expense represents a "return of" capital to the utility. The ratepayers should not be expected to pay a "return on" capital already recognized as being returned to the utility. Mr. Clark's adjustment corrects the balance sheet account to reflect this relationship between "return of and return on" capital. For purposes of calculating its 12/31/92 net plant values MPC shall reduce its gas and electric plant values by $373,708 and $1,842,482, respectively.

Nonconsumable Materials Charged to Materials and Supplies

69. MPC witness Miller testified that nonconsumable materials are items included in the materials and supplies inventories at Colstrip as original equipment replacement parts required for maintenance of the Colstrip units. These materials have specific applications and have limited or no alternate uses in a resale market. They differentiate from consumable materials

which have alternate uses. Currently, the accounting treatment for this material is to include all items in inventory as Account No. 154, Plant Materials and Operating Supplies. As a part is used, it is charged to the appropriate maintenance expense account. MPC wants to change the method of accounting to amortizing these items to maintenance expense over the expected lives of the plants and accumulate the amortized amount in Account No. 228.4, Accumulated Miscellaneous Operating Provisions. This account would be a rate base reduction in the next rate case, as is done through depreciation for the value of the plants themselves. The value of the subject materials as shown on the M&S inventory would be reduced by the estimated salvage value and any previous amortization as reflected in Account No. 228.4.

70. According to Mr. Miller, under the current accounting and ratemaking treatment, there will be a significant balance in Account No. 154, Plant Materials and Operating Supplies, when the Colstrip plants have served their useful lives and are removed from service. Therefore, MPC believes that the costs of materials needed to provide for uninterrupted operation of the Colstrip plants should be recovered from the ratepayers served by those plants rather than from ratepayers receiving service from MPC after the plants are retired. Future rate cases would show a rate base reduction for the balance of the accumulated amortizations.

71. MCC's witness on this issue was Mr. Clark. Mr. Clark stated that he is proposing to reverse MPC's proposed adjustment. He testified that MPC requested amortizing the existing balance of nonconsumable materials and supplies over the estimated remaining lives of the plants on the theory that (1) there will be a large balance of these materials and supplies on hand when the plants physically retire and (2) current ratepayers should be paying the costs associated with these materials and supplies. He disagreed that a large unusable balance will necessarily be stranded in the account when these plants are finally physically retired. Therefore, he opposed the proposed amortization. He further stated that the Commission should reject this proposal because it provides for a future, but not a current, rate base

reduction.

72. Mr. Clark stated five reasons MPC's proposal should be rejected: (1) MPC's proposal is based on speculation about what materials and supplies may or may not have alternate uses up to 28 years or more into the future; (2) as the plants approach the end of their physical existence, fewer and fewer of the materials and supplies will be reordered; (3) it is unlikely that both Colstrip Units 1 & 2 will be retired at the same time, and therefore materials and supplies on hand for one unit can be used in the other unit; (4) when these units finally reach retirement, MPC will likely study alternate uses for the units as they are doing with the Bird Plant; and (5) intergenerational equity among ratepayers is best served by the consistent application of sound ratemaking principles. A change in the accounting treatment would be counter-productive to that notion.

73. In rebuttal Mr. Miller testified that Mr. Clark has not done any studies to support why MPC should not make the proposed adjustment. Mr. Miller stated that Mr. Clark is not an expert nor has he obtained the services of an expert on this subject, and that his response is purely speculative. Mr. Miller maintained that his direct testimony is supported by an expert in this subject, Mr. Tom Olson, a registered professional engineer and site manager at Colstrip. He stated that in Mr. Olson's opinion, these materials and supplies will not have uses after these plants are retired. However, the inventory level must be maintained to sustain the reliability of the plants. Citing Mr. Olson, Mr. Miller stated that if some type of extension on the plants is undertaken after the useful life of the plants, the plants would not be built or configured as they are now. Finally, Mr. Miller characterized Mr. Clark's testimony as indicating that ratemaking treatment should change when the circumstances change. He believed that Mr. Clark and other MCC witnesses do not hold rigorously to the concept that consistent application of sound ratemaking principles is always best.

Commission Decision

74. On the issue of accounting for nonconsumable materials, the Commission finds that MPC's proposed accounting change is appropriate. These materials which are unique to the Colstrip

plants are purchased and kept on hand to help ensure the reliability of these generating facilities. After those plants are removed from service, these parts will have insignificant resale value. The Commission approves recovery of the cost of these parts through amortization over the remaining life of the Colstrip plants, which will match the costs of the materials to the operating lives of the plants. The Commission approves MPC's request to account for these items by amortizing the nonconsumable materials using Account No. 228.4, Accumulated Miscellaneous Operating Provisions. In this Docket the annual amount of the amortization is $193,970. In the future, if MPC extends the life of the Colstrip generating units, this amortization shall be reduced accordingly to reflect the increase in the expected life of the plants. As proposed by MPC, in future rate cases the accumulated amortization shall be reflected as a reduction to rate base.

75. At the hearing MPC offered Tom Olson, an engineer at Colstrip, for cross-examination on the nonconsumable goods issue. (Tr. p. 789) Mr. Miller had included a memorandum from Mr. Olson as an exhibit in his rebuttal testimony. The offer to parties to cross-examine Mr. Olson during the hearing was not proper. Mr. Olson did not file testimony in this case, nor did his name appear on MPC's witness list.

Approved Rate Base

76. The Commission approves an electric rate base for MPC of $941,175,323 on a total company basis. The resulting Montana jurisdictional approved rate base is $903,174,361 based on the results of the Rural Electric Cooperative (REC) Jurisdictional Allocation Study. The Commission approves a gas rate base for MPC of $240,966,898 on a total company basis.

REVENUE AND EXPENSE ADJUSTMENTS

Uncontested Issues

77. MPC and MCC agreed on a number of revenue and expense adjustments in this Docket: labor expense adjustment, future use gas wells, Shelby storage loss, AGA dues, labor related taxes, corporate overhead charges, pension costs, record keeping costs, fringe benefits excluding pensions, match test year sales to resources, nonrecurring least cost planning committee costs,

Mission Valley revenues and interest synchronization (method). The Commission accepts the positions agreed to by MPC and MCC.

Uncollectible Expense

78. In its filing MPC calculated a weighted average uncollectible rate using actual experience for the five year period from 1988 through 1992. MPC then applied this derived percentage to the test year residential and commercial class revenues to determine the test year uncollectible expense. The Commission adopted Mr. Clark's proposal to use a five year average for uncollectible expense in Docket No. 90.6.39.

79. Mr. Clark, however, does not believe that use of a five year average is appropriate to determine uncollectible expense in this case. He maintained that the historical five year period does not reflect the impact of the low income discount adopted by the Commission in Docket No. 90.6.39 which became effective November 1, 1991. Mr. Clark believed that one of the purposes of the low income rates is to reduce MPC's uncollectible expenses by providing a better opportunity for low income customers to pay their bills. Mr. Clark surmised that the low income discount has had a beneficial effect on MPC's uncollectible experience. As a result, it would be inappropriate to use the five year average as was done in Docket No. 90.6.39.

80. In this case Mr. Clark recommends using two years, 1991 and 1992, to calculate the rate of uncollectible expense to be applied against test year residential and commercial revenues. This proposal covers the entire time that the low income discount has been in effect. More important, it excludes the years prior to the institution of these programs.

81. For the gas utility MCC's adjustment would reduce test period uncollectible expenses by $52,948; the reduction for the electric utility would be $258,880.

82. In rebuttal, MPC witness Matosich testified that while the low income discount may have had a slight effect on uncollectible expense, another significant variable affecting this expense is weather. The years 1991 and 1992 were warmer than normal, which caused heating bills to be lower and allowed customers to be better able to pay their bills. The five year average ordered in Docket No. 90.6.39 was intended to normalize

the effects of the low income discount, weather, customer billing changes and other factors that affect the amount of uncollectible expense. After reviewing the five year average and finding that the expense is affected by several factors that do not remain constant from year to year, MPC believes that the adjustment warrants an averaging and that five years is appropriate.

Commission Decision

83. The Commission approves the five year average for uncollectible expense proposed by MPC. Use of the five year average as proposed by Mr. Clark in Docket No. 90.6.39 was approved by the Commission. By staying with the five year average the Commission retains consistency from the last rate case to this one. There is no evidence on the record on the effect of the low income discount on uncollectible expense. The low income discount may have reduced uncollectible expenses in 1991 and 1992, but the amount of that reduction is unknown. It appears that warmer than normal weather also played a role in the decline of uncollectible expense in 1991 and 1992. The Commission finds the use of a five year average to be appropriate in the development of uncollectible expense in the test year. In future rate filings, the five year average will include more years in which the low income discount has been in effect.

1988 Software Amortization

84. On September 7, 1993, Mr. Clark filed response testimony in this Docket. Mr. Clark stated that the five year amortization period used for the 1988 software ended in December, 1993. Therefore, to reflect the known and measurable cessation of the amortization expense during the adjustment period, Mr. Clark removed the costs associated with the 1988 software. (MCC Exh. 10, pp. 13, 58-59)

85. On October 18, 1993, MPC filed rebuttal testimony in the Docket. Mr. Reardon opposed Mr. Clark's adjustment, stating that the test period should reflect five vintage years of computer software amortization expense in the cost of service. Mr. Reardon acknowledged that MPC replaced the 1987 software, which became fully amortized at December 31, 1992, with the 1992 vintage software to reflect the five-year cycle of amortization expense. (MPC Exh. 33, pp. 9-10)

Commission Decision

86. MCC is correct that the amortization of the 1988 software clearly ends within the change period. MPC does not dispute this fact. The Commission finds that the MCC adjustment excluding the 1988 software is appropriate.

87. In Order No. 5360d, Docket No. 88.6.15 (test year 1987), the Commission found that replacing the 1982 and 1983 software with 1987 and 1988 software was appropriate. However, the record in this Docket does not contain a proposal from MPC to include the 1993 software, nor does it include the amount of the 1993 software. The record in Docket No. 88.6.15 included both of these items. Therefore, the Commission finds that the 1993 software shall not be included in this Docket.

88. The revenue requirement impact of eliminating the 1988 software is a reduction of $70,527 for the Electric Utility and a reduction of $23,423 for the Gas Utility.

Power Supply Costs

89. The one remaining contested issue in power supply costs had to do with off-system sales in the test year. Consistent with MPC's recent general rate filings, the monthly energy amounts for other off-system sales are based on four-year averages. In this Docket the four-year average is 1989 to 1992. MPC witness Pascoe testified that including these four-year average quantities in the test year along with the new firm energy sale to BPA would result in unreasonably large quantities of total off-system sales quantities in the test year. He proposed an adjustment to remove the sale to BPA from total off-system sales.

90. Mr. Clark disagreed with the MPC proposal to reduce non-firm off-system sales by the amount of energy sold to BPA under a firm contract. He contended that allowing Mr. Pascoe's adjustment would deprive the ratepayers of the benefit of the firm BPA sale and that the resulting non-firm off-system sales levels would be too low for test year purposes.

91. If the Commission allows Mr. Pascoe's adjustment, Mr. Clark recommended that the Commission revisit its consistent use of averages for most of the components of the net power supply costs. That is, rather than locking in the generation

from the thermal units as some historical average and allowing off-system purchases to be the "swing" or residual resource, perhaps the lowest cost resources should always be set at a maximum attainable level.

92. According to Mr. Clark, the test year revenue requirement would be substantially lower if the Corette resource were used to meet the load adjustments that he recommends instead of the off-system purchases. Based on Corette's performance in most years, it is capable of producing sufficient energy to meet these additional loads. Mr. Clark believed that the Commission should continue the long standing policy of using actual averages for the power supply components.

93. In rebuttal Mr. Pascoe disagreed. He noted that MPC's proposed test year volumes for total off-system sales and short-term purchases range from 103 percent to 120 percent of the actual average quantities for the last four years and the last seven years. If the two lowest years for off-system sales (1987 and 1988) and short-term purchases (1986 and 1990) are removed, MPC's proposed volumes still exceed the averages for the remaining five years.

94. In contrast, MCC's recommendation (according to MPC) would result in test year volumes for off-system sales and short-term purchases varying from 126 percent to 151 percent of the historical averages. MPC maintained that MCC's proposed quantities were not achieved in any of the last seven years for either off-system sales or short-term purchases. Mr. Pascoe indicated in rebuttal that accepting Mr. Clark's recommendation might affect future off-system sales contracts. MPC would interpret such a decision to mean that if MPC enters into future multi-year off-system sales contracts, the Commission might expect MPC to make these new sales in addition to maintaining historical averages for short-term off-system sales. To the extent MPC believes this to be an unrealistic expectation, MPC will have a disincentive to pursue otherwise attractive multi-year transactions.

Commission Decision

95. For total off-system sales levels, MCC recommends 2,572,359 MWH vs 2,105,799 MWH recommended by MPC. The

difference of 466,560 MWH is the amount now being sold to the BPA. Total actual off-system sales achieved by MPC for the twelve month time periods December 1992, January 1993 and August 1993, were 2,463,404 MWH, 2,515,691 MWH, and 2,556,607 MWH, respectively. These results are within 99 percent of Mr. Clark's total and are trending upward. Given the upward trend in total actual off-system sales, the Commission finds that MCC's adjustment for the BPA sale is appropriate in this Docket.

96. MCC points out that the methodology will self-adjust over time to avoid the problem perceived by MPC. If MPC makes more long-term sales and uses its facilities such that it cannot attain historical levels of other off-system sales, the average will decline over time. Including the BPA sale in total off-system sales results in a decrease in the revenue requirement of $906,167.

WIM Reporting Requirements

97. Mr. Pascoe cited FOF 56, Order No. 5484p, Docket No. 90.6.39, which indicated that Washington Idaho Montana (WIM) reporting requirements could be changed if it became apparent that the routine activities among Washington Water Power, Idaho Power Company and MPC had no bearing on other activities within the group. (MPC Exh. 43, p. 44) As an alternative to the current system, Mr. Pascoe suggested that MPC report to the Commission if MPC becomes involved in studies similar in nature and scope to the WIM studies performed in 1987 and 1988.

98. The Commission wishes to maintain the current WIM reporting requirements. During a future review the Commission will examine the preparation of the WIM reports to determine if the work is burdensome. If so, the Commission will consider new WIM reporting requirements.

Year End Customer Counts

99. To compute revenues from rates, Mr. Clark used the number of electric and gas customers actually served at the end of the 1992 test period and their average annual usage. MPC adjusted the year end customer revenues to account for seasonal and other variations in customers and usage.

100. The controversy involves the interpretation by the parties of ARM 38.5.606(1)(e) of the optional filing rules. It

reads:

> For matching purposes, test year revenues shall be restated to reflect end of year customer counts and the annualization of known changes in revenues occurring during the test year.

MPC asserts that its adjustment to year end customer counts is contemplated by the "annualization" requirement of the rule. MCC says that the word "and" after the words "customer counts" suggests that the annualization requirement is separate, and does not apply to the specific year end customer counts requirement of the rule.

101. Beyond the technical controversy of interpreting the rule, MPC witness Corcoran says that customer counts must be adjusted to more accurately reflect customer growth during the rate effective period: "It is important that any method which adjusts the number of customers accounts for growth (+) or (-) and also maintains the proper seasonal pattern. This is because the monthly test period consumption increases (or decreases) by an amount equal to the adjustment in the customer count multiplied by the average kWh usage per customer. Hence, the use of adjusted customer counts that do not reflect actual conditions produces revenues that do not reflect reality. MPC does not believe this was the intent of the Commission's Optional Rule requiring this adjustment." (MPC Exh. 9, p. 7, lines 20-26, and p. 8, lines 1-2)

102. Mr. Clark is critical of any adjustment to year end customers, particularly the method first used by MPC in this case: "The result of MPC's manipulation of the end of year customer count is that there are varying customer counts, by month, used to determine the test year revenues from present rates. Indeed, in some months, MPC's Adjusted Customer Count is below the actual 1992 customer count (August, September, October and November)." (MCC Exh. 10, p. 9, lines 14-19)

103. MPC corrected its method in its rebuttal case. In making the correction, Mr. Corcoran said: "As was explained previously, the monthly customer counts include this annual net growth component along with variations due to seasonal customers,

temporary customers, and the movement of customers between classes. MPC is considering performing an analysis to isolate the true net customer growth from these other variations. Absent this information, it was necessary to develop a methodology to assign a portion of this net annual growth to each month." (MPC Exh. 9, p. 9, lines 8-15)

104. Even after its correction, MPC used different methods to "shape" the customer counts for the gas and electric utilities: "The gas calculation assumes that the annual customer growth occurred in a linear fashion or that 1/12 of the annual customer growth occurred each month. The electric calculation assumes that the monthly customer growth occurred proportional to the average monthly use per customer." (MPC Exh. 9, p. 9, lines 17-21) Mr. Corcoran asserts that the two methods produce very similar results. Lower revenue requirements for both the gas and electric utilities result from using the MCC customer count methodology. The gas revenue requirement reduction is about $735,000, and the electric revenue requirement reduction is about $432,000 for the test year.

105. The only previous Commission action involving the year end customer counts issue was its decision in Mountain Water Docket No. 92.4.19, Order No. 5625b issued on June 4, 1993: "The Applicant, in Exhibit C, proposed total test period operating revenues of $4,933,900. MCC proposed two adjustments increasing the operating revenues of MWC. MWC has accepted the proposed adjustment increasing revenues by $16,099 to reflect year end customer counts." (Id., FOF 56) MCC's proposed adjustment in the present MPC Docket is identical to that which the Commission ordered in the Mountain Water Docket.

Commission Decision

106. The Commission finds that the MCC adjustment is proper in this Docket, as in the Mountain Water Docket. The language of the optional filing requirement rule is specific and plain when it talks about the "restatement" of revenues to reflect end of year customer counts. If MPC's logic were adopted, the revenues associated with customer counts first would be "restated," and then "annualized." This interpretation seems illogical and clumsy. The annualization requirement of the rule is general and

meant as a catch-all to apply to unforeseen items, as well as to items such as rate changes which occur at some point during the test period.

107. Ratemaking fairness and matching are well served by the MCC year end customer counts adjustment, when applied in the context of the rest of the optional filing rules. The MCC adjustment does not "shape" customer counts in any way. Similarly, the MCC does not "shape" the year end rate base plant items that are used to provide service to every year end customer. A quid pro quo for MPC's adjustment, which eliminates customer counts and usage associated with seasonal usage, might be to eliminate plant used to serve seasonal customers.

108. The test year providing the best and most certain matching of plant, revenues and expenses is an average historical rate base test year, without adjustments. The Commission made various concessions to assuage utility concerns that strict adherence to pure average rate base ideology would not allow an opportunity to earn the authorized rate of return. A substantial movement in this direction is the optional filing rules. A test year end rate base approximates the plant used to provide post test year service; test year end customers approximate those served after the test year; and test year end expenses approximate those incurred after the test year.

109. The Commission finds the reasoning and arguments of the MCC to be compelling, and therefore, it accepts the MCC adjustments to year end customer counts.

Year End Employee Count

110. Mr. Clark made an adjustment based on PSC Data Request No. 138 to reduce labor costs to reflect the number of employees as of the end of the test year. MPC reduced its labor force during 1993 from 2,391 to 2,373 -- a total reduction of 18 employees. The proposed adjustment was developed by applying the end of year employee count against the average test year cost per employee on an actual basis. This adjustment reduced labor expense by $125,466 for the gas utility and $357,567 for the electric utility.

111. MPC objected to Mr. Clark's proposed adjustment because the Company calculates test year labor expense based on total

actual labor expense for the year and feels that this methodology appropriately reflects changing employee counts through the year.

Commission Decision

112. The Commission accepts MCC's adjustment for year end employee counts. This adjustment is consistent with the use of a year end rate base and year end customer count which the Commission has approved in other sections of this Order.

The Attrition Adjustment

113. Optional filing rule ARM 38.5.606(1)(c) permits an attrition adjustment. Any test year cost for which a known and measurable change is not proposed may be multiplied times the Consumer Price Index (CPI) and times a factor of 45 percent. This calculation approximates a year end expense level, which is matched by requirements in ARM 38.5.606 for a year end rate base, year end customer counts and year end revenues.

114. An important assumption that underpins the calculation in ARM 38.5.606(1)(c) is that the expenses to which it applies are incurred uniformly throughout the year. For example, as of June 30 in a calendar year, the utility will have incurred exactly one half of yearly expenses.

115. Another assumption is that the utility will be efficient as it incurs expenses. Thus, implicit in the 45 percent factor is that 10 percent of the annual CPI rate is a productivity improvement factor. Without the productivity factor, the 45 percent would be 50 percent.

116. The question of what constitutes the "appropriate" CPI rate is at the heart of the debate between MPC and MCC. MPC uses 3 percent, which is the percentage change between the 1991 and the 1992 annual average CPI rates for urban consumers. The MCC uses 2.75 percent, which is the percentage change between the January 1992 and the December 1992 CPI rates for urban consumers.

117. In support of the MPC position, Mr. Matosich testified: "The Company's calculation (year to year) is more appropriate than applying a beginning and ending monthly computation because an annual comparison is more indicative of the CPI, as contemplated by the rules." (MPC Exh. 38, p. 7, lines 1-5)

118. To the contrary, Mr. Clark testified: "The Commission

is attempting to provide an unspecified `attrition' adjustment, based solely on a change in the CPI, to recognize the possible cost increases that may have occurred during the test year, but are not subject to specific adjustment. It follows, therefore, that the appropriate measure is from January to December for a calendar test year rather than some `average annual' increase, the derivation of which, is not even evident from the face of the document from which it came." (MCC Exh. 10, p. 39, lines 3-12)

119. In the context of the 1992 test year, the MCC adjustment causes a revenue requirement reduction of $13,372 for the gas utility and $46,450 for the electric utility. The Commission determines that the CPI number developed by the MCC for the 1992 test year is appropriate. MCC's method should be refined in future cases to more accurately reflect the monthly urban CPI changes that occur during a test year. However, for the purposes of this record and order, the concept of updating expenses for the CPI change during the test year and the number MCC used are acceptable.

120. The rationale and CPI number of MPC are unacceptable in this case. The difference between the two yearly averages includes effects of CPIs reaching as far back as January 1991 and as far forward as December 1992. To use the effects of 1991 CPI numbers to adjust expenses incurred in the 1992 test period would be double-counting. The 1992 expenses by definition include the effects of price changes that occurred in 1991.

Miscellaneous Revenues Issue

121. According to the NARUC Uniform System of Accounts, some of the items in a utility's miscellaneous revenue accounts may include commissions on sales or distribution of electricity of others when sold under others' rates filed; compensation for minor or incidental services provided for others such as customer billing and engineering; profit or loss on sale of materials and supplies not ordinarily purchased for resale and not handled through merchandising and jobbing accounts; sales of steam except for sales by a steam-heating department or transfers of steam under joint facility operations; revenues from transmission of electricity of others over transmission facilities of the utility; revenues from operation of fish and wildlife and

recreation facilities included in utility plant; and amounts received from public authorities to defray maintenance expenses.

122. There are several miscellaneous revenues issues at issue between MPC and MCC in this case. The principle contested issue remaining involves the inflation adjustment to the miscellaneous revenues of MPC. For the electric utility, Mr. Clark proposed adjustments totalling $87,475, to the following miscellaneous revenues accounts: 451.4 Temporary Service; 451.5 Other; 454.5 Leased Apparatus; 456.12 Sale of Steam; 456.13 Loading MPC Salaries; 456.23 PCB Analysis; and 456.1 Commissions on Other Energy. Mr. Clark maintained that the actual balances and the MPC test year balances in these accounts were not representative of recent history. Therefore, he used averages for these accounts.

123. Another of Mr. Clark's adjustments is to account 456.71, Colstrip 3-MPSC phase in, used to book the Colstrip 3 phase-in revenues. MPC overcollected $94,057 from its retail customers, which it proposed to eliminate from the test year and keep for itself. Mr. Clark's adjustment of $47,029 returns the money to ratepayers over a two year period.

124. Mr. Clark used a CPI index of 2.75 percent x 45 percent to adjust all other miscellaneous revenues items. For the 1992 test period, this CPI adjustment for the electric utility is $12,586 and for the gas utility it is $31,986. Mr. Clark reasoned that the same CPI factor should be applied to unadjusted miscellaneous revenues as is applied to unadjusted test year expenses: "The recognition of a similar adjustment to the miscellaneous operating revenues is required to help balance the interests of the ratepayers and the shareholders. These revenues are expenses for the other entities that are similar to the types of expenses that are affected by the attrition adjustment. It is just as reasonable to assume an increase to these revenues based on nothing more than a change in the CPI as it is to accept the expense adjustment that the optional filing rules contemplate." (MCC Exh. 10, pp. 15-16, lines 18-24 and 1-3)

Commission Decision

125. The Commission finds that the inflation adjustment for "miscellaneous" expenses is exactly the same as this inflation

adjustment for "miscellaneous" revenues. Use of a multiplication factor to estimate a composite value for these expense and revenue categories suggests that the individual components of the categories are too small to be efficiently considered by themselves. The factoring process espoused by the MCC for both miscellaneous revenues and expenses suggests that these categories will tend to change, just as general price levels change over time. It would not be consistent to pluck out of either category single items for purposes of comparing them to actual results, as MPC has attempted to do. The general price level adjustments are either appropriate in total for both miscellaneous expenses and revenues, or not appropriate at all.

126. Reasonable business practices suggest that as general expense levels change, so will the revenue levels change. It is not logical to expect that a business, over a reasonable period of time, will simply absorb general expense level increases without raising additional revenues, including miscellaneous revenues, to pay such expenses. The Commission finds MCC's reasoning and arguments of the MCC to be compelling, and therefore accepts the MCC adjustments to miscellaneous revenues.

The Canadian Withholding Tax

127. The Montana Power gas utility is comprised of three corporations, two of which are Canadian. Income taxes are paid to the Canadian government when the profits from the Canadian corporations are paid or "dividended" to the U.S. parent, MPC. In the past, such payments have been made about every five years. Accordingly, the Commission has amortized the related taxes over five years. Starting in 1991, the payments or dividends have been made each year. Mr. Clark proposed to continue the 5 year amortization of the 1990 Canadian withholding tax as it was approved in Docket No. 90.6.39 and to allow the 1993 tax amount on a current basis. (MCC Exh. 10, pp. 13-15) MPC objected to Mr. Clark's proposal, maintaining that it does not recognize the withholding taxes paid in 1991 and 1992 and that the withholding tax expense for 1993 was abnormally low, i.e., not truly representative for ratemaking. The 1991 tax was $305,130, the 1992 tax was $285,091 and the 1993 tax was $39,066. (MPC Exh. 41, pp. 2-3)

128. The MCC adjustment reduces the revenue requirement of the gas utility by $194,808.

129. The principal dispute between the MCC and MPC on this issue pertains to Mr. Clark's recommendation to disallow the 1991 and 1992 taxes. Mr. Clark does so because the Canadian subsidiaries have started to pay dividends on a yearly basis to MPC, and therefore, to incur taxes on a yearly basis. To "track" the yearly dividend related taxes in this proceeding and amortize them over future periods would be improper, retroactive ratemaking. The Commission agrees with Mr. Clark on this point.

130. The other dispute is whether 1993 truly reflects the annual dividend payments and taxes that MPC will receive. MPC witness Kindt testifies it does not, which is not controverted by Mr. Clark: "The withholding taxes paid related to Canadian earnings can vary considerably from year to year." (MPC Exh. 41, p. 3, lines 14-16)

Commission Decision

131. The Commission must balance Mr. Kindt's statement against its known and measurable principle, suggesting that the 1993 "known and measurable" tax is the proper one to use. The Commission considers as a compromise the use of a representative average of the test year and change year tax expenses of $285,091 and $39,066, modifying Mr. Clark's adjustment from a $194,808 reduction in revenue requirement to about $71,795. Mr. Clark indicated during the hearing that perhaps he should have considered the tax expenses from the other years when he made his adjustment. (Tr. pp. 887-888) The Commission finds appropriate the representative average tax expense of $71,795.

Normalization of Taxes

132. During 1992, MPC adopted FAS No. 109. Before FAS No. 109, MPC's accounting for income taxes was governed by FAS No. 71 "Accounting for the Effects of Certain Types of Regulation," and Accounting Policy Board (APB) Opinion 11 "Accounting for Income Taxes." Under FAS No. 71, the utility could not record deferred income taxes and the related assets (receivables for future recovery of taxes from customer) if income taxes payable in future years would be recoverable through rates. Therefore, book accounting and ratemaking both used flow-

through accounting and did not require recording of deferred taxes or liabilities for income taxes which were flowed through to ratepayers. The utility would dislose the cumulative net amount of timing differences for which deferred income taxes were not provided in a footnote to the published financial statements.

133. Under FAS No. 109, a company calculates both a book balance sheet and a tax balance sheet. If differences between the two result from temporary differences, deferred income taxes are provided. FAS No. 109 also recognizes that under the flow-through method of ratemaking, these taxes will be recovered from ratepayers and result in additional tax liability. Regulated enterprises may not use the flow-through method of accounting for book purposes. Utilities must record assets or liabilities, as calculated under FAS No. 109, and reflect them in the balance sheet, just as for any nonregulated company. MPC's regulatory asset is almost $138 million. Items previously flowed through are plant related and include, in part, the State effect of accelerated depreciation, AFUDC, ITC, Colstrip 3 carrying charges, removal costs and salvage, and pre-1981 property additions which are almost fully depreciated for tax but have remaining book basis.

of J MPC recommended that the Commission fully normalize income taxes. This normalization is not required by either federal or state tax law. MPC recommended the South Georgia method as the means to convert from flow-through to normalized ratemaking. Under this method, the previously flowed through amounts are reflected in rates evenly over the average remaining life of the Company's property, stabilizing rates and providing a long amortization period for the previous tax benefits.

135. Mr. Clark opposed MPC's request to move to full normalization. Mr. Clark maintained that long ago the Montana Commission opted to base revenue requirements on the basis of actual taxes paid to the extent allowed by Federal and State law. While current tax law may permit fewer tax timing differences than were available prior to 1981, it does not necessarily follow that the actual dollars related to these tax timing differences will be lower than those in past years.

136. Using any positive discount rate, on a present value

basis, the difference in the revenue streams depicted by Mr. Kindt will always favor the current ratemaking theory. Therefore, the ratepayers would be prejudiced by switching to "full" normalization at this time.

137. Rates have been set consistently for many years using the existing theory of flow-through. Since there is never an exact customer match from one year to the next, intergenerational equity should be based on the application of a consistent theory among generations of customers, unless circumstances change that would warrant a change in the applicable theory. That is not the case here.

138. In rebuttal, Mr. Kindt testified that it is possible that taxes could be shifted from large customers exiting the system to smaller customers. Large customers of both the gas and electric systems are constantly looking for ways to lower costs. Because of their size, they have options unavailable to smaller customers, such as self-generation or off-system gas purchases. If large customers do leave, remaining customers will have to pay for costs previously deferred to future years. Therefore, it is in the best interest of the majority of MPC's customers to reduce the level of costs, including income taxes, deferred for recovery in future years.

139. The revenue requirement differences for full normalization of taxes between MPC and MCC are $3,114,211 for the Electric Utility and $774,517 for the Gas Utility.

140. Mr. Clark argued that even if there are no future timing differences, if one uses any positive discount rate, on a present value basis, the differences in the revenue streams will always favor current rate theory. However, Mr. Kindt testified that full normalization provides an offsetting advantage by reducing rate base provided by accumulated deferred income tax. Thus, the issue of which method provides the lowest long-term costs depends on individual customers and their financial situation.

141. The reversal of prior temporary differences has already begun. For Colstrip Units 1 and 2 that reversal will continue at the present rate until the plants reach the end of their 28-year tax lives in 2002 and 2003 at which time taxes will increase

significantly. According to MPC, starting full normalization now will assure that ratepayers using the utility system from this point forward will share equally in the recovery of the previously flowed through tax benefits. Present customers should not be allowed to benefit from lower rates at the expense and burden of future customers.

142. MPC must recognize the $138 million regulatory asset on its books as a result of FAS No. 109. This sum is a ratepayer liability resulting from paying taxes on the basis of tax deductions that are greater than current book expenses and book expenses that will still be occurring toward the end of the affected plant's life after the tax deduction related to that expense has been used.

143. At the hearing Mr. Kindt stated:

> Changes in the tax code allow fewer accelerated deductions and the ones that are presently known will not be large enough to offset the reversals. (Tr. p. 824)

MCC noted that this does not mean that timing differences will cease to exist and that there has been no attempt to quantify future levels.

144. MCC pointed out that Mr. Kindt claimed that:

> The Company's proposal will allow this $140 million to be amortized evenly over a period of approximately 26 years, rather than unevenly over a much shorter period of time under the flow-through method. (Tr. p. 823)

The 26-year period relates to the remaining life of the plant which gave rise to the timing difference. Under either method, the difference must reverse over that same 26 year period. Under the flow-through method, the reversal would be delayed into the future. Toward the later years, the remaining reversals relating to particular items of plant would theoretically be larger. The end result will be a zero timing difference. Indeed, the benefit provided by this deferral is one of the reasons for adopting and maintaining the flow-through treatment.

145. MPC and MCC agree that the $138 million regulatory asset will have to be recovered from ratepayers over the

remaining life of those assets. MPC noted that changes in the tax law have greatly reduced the amount of tax timing differences realized in the past. Mr. Kindt stated that the accelerated tax deductions presently known will not be large enough to offset the reversals. (Tr. p. 824) It is impossible to predict how Congress will change tax laws in the future.

146. The Commission is not persuaded by MPC's argument that by normalizing taxes large customers will pay their portion of the reversal of the $138 million earlier than they would under flow-through. Under that logic as many costs as possible would be crowded into today's rates with the effect of driving large customers to seek alternatives even sooner than they otherwise would. Also, taxes are and have always been the responsibility of all customer classes.

147. MPC argued that intergenerational equity would be improved by changing from flow-through to full normalization. On the other side, Mr. Clark noted that rates have been set consistently for many years using the existing theory of flow-through. Since there is never an exact match from one year to the next, intergenerational equity should be based on the application of a consistent theory among generations of customers, unless circumstances change that would warrant a change in the applicable theory, which has not happened here.

Commission Decision

148. The Commission determines that it should follow the long-established precedent of setting rates based on actual taxes paid and deny MPC's request to change to full normalization. Staying on flow-through will have the benefit of lower tax expense for many years into the future. The Commission agrees that as assets reverse in future years those reversals will become part of the calculation of income taxes.

Other Post Employment Benefits (OPEB)

149. The Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106 (FAS 106) in December 1990. FAS 106, Employer's Accounting for Postretirement Benefits Other Than Pensions, is effective for fiscal years commencing after December 15, 1992. Examples of Other Post Employment Benefits (OPEB) are medical, dental and life insurance

benefits. These benefits do not spontaneously arise when the employee retires, but are instead promised to the employees while they are still employed. FAS 106 requires that companies recognize the expense of OPEB during the time the employees work in order to match the expense with the time period that benefits are earned.

150. On September 2, 1992, MPC filed an application with the Commission for an Accounting Order allowing the Company to accumulate and defer certain OPEB costs in connection with the implementation of FAS 106. MPC adopted FAS 106 for financial statement purposes effective January 1, 1993. Specifically, MPC requested Commission approval to accumulate and defer the costs incurred by the Company that exceed the costs currently recognized for ratemaking purposes. This application was assigned Docket No. 92.9.48.

151. MPC stated in its application, "Applicant understands that if the Commission issues the requested Accounting Order, it has the full burden of proof to demonstrate that such accumulated amounts are properly included in the revenue requirement in MPC's next general rate case."

152. On November 9, 1992, the Commission granted MPC's request for an Accounting Order. The Commission found that MPC may accumulate and defer the OPEB costs incurred by MPC pursuant to FAS 106 that exceed the Pay As You Go (PAYG) costs for a given year. For example, in 1993 the amount deferred would equal the difference between the 1993 FAS 106 amount and the 1993 PAYG amount. The deferral may begin on January 1, 1993. (Order No. 5653, FOF 6)

153. The Commission also found that MPC will have the opportunity, as well as the burden, to demonstrate in its next general rate case: (1) the appropriate level of OPEB costs to be recovered through ratemaking; and (2) the proper recovery period for those OPEB costs. (Order No. 5653, FOF 8)

154. On June 21, 1993, MPC filed direct testimony in this Docket. Mr. Miller supported MPC's requested OPEB adjustment. Mr. Miller stated that MPC currently recognizes OPEB costs on a Pay As You Go (PAYG), cash basis. He proposed ratemaking treatment consistent with FAS 106 for the accrual of OPEBs. (An

exception is that MPC proposes to remain on PAYG for medical and life insurance benefits for current retirees and medical insurance for key employees. The total liability for these benefits is low and/or payments will be received by the employees in the next few years.) MPC maintains that the benefits are earned during an employee's working career, and recognition of this fact through the accrual method results in a better matching of the employee benefit costs with the utility services from which those costs arose.

155. Mr. Miller indicated that MPC plans to fund the entire amount of the expense computed in accordance with FAS 106 to the extent that funded amounts can be deducted for state and federal income tax purposes. MPC proposes to treat unfunded amounts as customer contributed capital. In this Docket, the entire FAS 106 accrual is tax deductible. MPC intends to use both a Voluntary Employees' Beneficiary Association (VEBA) trust and a Retiree Medical Account within a Pension Plan as funding vehicles. (MPC Exh. 15, pp. 4-6, 9-10)

156. On September 7, 1993, MCC filed response testimony in this Docket. MCC witness Towers recommended that MPC continue its long-standing practice of accounting for OPEB costs on a cash basis. Mr. Towers maintained that the proposed accrual for OPEB costs reflects estimated costs which are neither known nor measurable with reasonable confidence. Therefore, the matching of service costs and service benefits, which typically can be achieved with accrual accounting, cannot be achieved with the OPEB accrual. Mr. Towers further contended that matching cannot be achieved since the FAS 106 accrual includes the amortization of the Transition Benefit Obligation (TBO), which represents benefits from past service periods.

157. Should the Commission approve the accrual method for ratemaking, MCC recommends the following:

a. Remove and permanently disallow the past service related costs (i.e., the FAS 106 "Transition Obligation"), together with the associated interest on the Transition Obligation.

b. Modify the accrual to extend the "attribution period" to the employee's expected actual retirement date (i.e., versus the eligibility date).

c. Modify the claimed accrual by reducing Montana Power's assumed health care inflation rates to recognize the Clinton administration's commitment to health care cost containment. If guidelines are not available, MCC recommends reducing MPC's initial health care inflation rate from 12 percent to 8 percent to more appropriately reflect MPC's past experience and reducing the 8 percent rate by 25 basis points per year until it reaches the 5.75 percent final rate (in 2002) used in the Company's forecast.

d. Eliminate the amortization of the FAS 106 costs deferred between January 1, 1993 and the rate effective date in this case.

(MCC Exh. 1, pp. 35-39)

158. On October 18, 1993, MPC filed rebuttal testimony in the Docket. In addition to Mr. Miller, Mr. Wickes also testified regarding OPEB. Mr. Wickes maintained that the FAS 106 accrual is known and measurable. First, actuarial studies will be performed annually, reflecting changes in plan benefits coverage, earnings assumptions, and inflation rates. These studies provide a basis for ongoing analysis. Second, all long-range cost projections necessarily incorporate a degree of uncertainty. However, methods have been developed to make actuarially sound projections of future OPEB costs. MPC continues to recommend use of the FAS 106 accrual for ratemaking. (MPC Exh. 17, pp. 2-4)

159. Mr. Wickes presented testimony revising MPC's initial health care cost trend rate. In its original testimony MPC proposed rates beginning at 12 percent in 1993 and decreasing to 5.75 percent in the year 2002. Mr. Wickes' testimony reflects MPC's revised rate beginning at 9 percent in 1993 and decreasing to 5.75 percent in the year 2002. Mr. Wickes noted that the trend rate of 9 percent is consistent with the experience of MPC. (MPC Exh. 17, pp. 8-9)

160. Mr. Miller continued to support recovery of both the TBO and the 1993 deferred amounts and the use of the full eligibility date in determining the attribution period.

161. MPC's rebuttal proposal results in an increased revenue requirement of $1,386,523. (Electric $1,049,598; Gas $336,925)

FAS 106 vs PAYG

162. The Commission recognizes that an increased level of OPEB expenses are placed on current ratepayers when FAS 106 is

implemented. However, to ignore the increasing liability and leave it for future generations is not the appropriate course of action. The Commission finds that the full accrual method of accounting for OPEB is a preferable means of matching the employee benefit costs with utility services from which those costs arose.

163. MCC contends that matching cannot be achieved because (1) the FAS 106 accrual includes the amortization of the TBO, which represents benefits from past service periods; and (2) the proposed accrual for OPEB reflects estimated costs which are neither known nor measurable with reasonable confidence. The Commission is not persuaded by these arguments. When there is a change in an accounting method which affects timing, a transition payment must be considered. MPC has proposed to amortize the TBO over 20 years, stating that this is a long, but still temporary, recovery period. MPC has also correctly stated that the PAYG method is flawed because it never matches costs to the period when they are incurred.

164. Mr. Wickes testified that long-range cost projections necessarily incorporate a degree of uncertainty, but there are methods to make actuarially sound projections of future OPEB costs. Specifically, annual actuarial studies will reflect changes in plan benefits coverage, earnings assumptions, and inflation rates. These studies provide a basis for ongoing analysis. (MPC Exh. 17, pp. 2-4) The Commission notes that in the ratemaking process assumptions are updated as future information becomes available.

165. Mr. Wickes also testified that much of the uncertainty involved in projecting OPEB costs is not present for MPC. MPC has established a cap for medical benefits prior to age 65, removing uncertainty because estimates of inflation rates beyond the cap are not considered. Also, retirees over age 65 receive a set amount ($3 per month) for medical expenses.

166. The Commission finds that the FAS 106 accrual represents a reasonable matching of the OPEB expense with the service received.

167. The Commission will next address the four areas of disagreement between MPC and MCC regarding the FAS 106

calculation: inclusion of the TBO; the appropriate attribution period; the assumptions used, specifically the initial health care cost trend rate; and inclusion of the amounts MPC has deferred since January 1, 1993.

TBO

168. MCC recommends permanently disallowing the entire TBO, stating that present and future ratepayers are not responsible for TBO costs and should not have to pay higher rates so that MPC may recover these costs. (MCC Exh. 1, p. 36) MPC maintains that the issue is not whether the TBO will be collected from ratepayers, but when it will be collected. (MPC Exh. 16., pp. 9-10)

169. The change from PAYG to FAS 106 is a change in accounting methods, or how to account for the same costs over a different time period. MCC has not recommended disallowing the current PAYG costs, yet these costs clearly arose from past service. The Commission finds that the TBO shall be included in the FAS 106 calculation. MPC has proposed to amortize the TBO over a 20 year period. The Commission finds that a 20 year amortization is reasonable and accepts MPC's proposal.

Attribution Period

170. The attribution period is that period of an employee's service to which the expected OPEB obligation is assigned. In accordance with FAS 106, MPC's proposal reflects an attribution period through the employee's full eligibility date (age 55 and 30 years of service). To attain proper matching, MCC maintains that an employee's expected retirement date (age 61), not the full eligibility date, reflects the proper end of the attribution period. MCC contends that calculating the attribution period through the eligibility date instead of the expected retirement date improperly shortens the time period over which the OPEB costs are accrued. (MCC Exh. 1, pp. 17-18, 36-37)

171. For example, an employee hired at age 26 meets the full eligibility criteria at age 56. Since the expected retirement date for MPC employees is age 61, the difference is whether the expected OPEB benefits accrue from age 26 through age 56 or from age 26 through age 61. MPC has done a study showing that the difference resulting from the MCC proposal is a reduction in the

annual FAS 106 expense of approximately $100,000.

172. The Commission finds that the expected retirement date is more appropriate than the full eligibility date in terms of matching OPEB costs with employee service and shall be used in calculating the FAS 106 accrual.

Health Care Cost Trend Rates

173. MCC maintained that the health care cost trend rate used by MPC was too high and recommended that the rate be revised to better reflect MPC's past experience. Specifically, MCC recommended that MPC's initial rate of 12 percent be reduced to 8 percent. (MCC Exh. 1, pp. 13-14)

174. In response to MPC Data Request No. 26, Mr. Towers clarified that MPC's experience from 1988 through 1992 had been 9.02 percent, not slightly below 8 percent as indicated in his testimony. In its rebuttal filing MPC revised the beginning rate from 12 percent to 9 percent. This amount trends downward until 2002 when the final rate of 5.75 percent is reached. (MPC Exh. 17, pp. 8-9)

175. During the hearing Mr. Towers testified that his recommendation remained at 8 percent, which reflects a one year increase from 1991 to 1992. (Tr. pp. 332-333) Mr. Towers indicated in his prefiled testimony that changes from year to year are not consistent. In fact, MPC's recent history has included both increases and decreases in claims per employee. (MCC Exh. 1, pp. 14) Because of this variability, it is more reasonable for ratemaking purposes to look at recent experience from 1988 through 1992 (MPC's proposal) than to consider only 1992 (MCC's proposal). The Commission finds that the health care cost trend rate beginning at 9 percent as presented in MPC's rebuttal testimony is reasonable and shall be used in the FAS 106 accrual calculation.

FAS 106 Deferral

176. The November 1992 Accounting Order No. 5653 (Docket No. 92.9.48) granted MPC's request to accumulate and defer the difference between the FAS 106 accrual and PAYG costs effective January 1, 1993. MPC maintains that it has deferred OPEB costs in accordance with the accounting order and is requesting recovery of amounts deferred. MPC is proposing that the deferral

be amortized over 18.75 years to recover the entire amount within 20 years from the date the accrual began.

177. MCC has recommended that the Commission eliminate the amortization of the FAS 106 costs deferred between January 1, 1993, and the rate-effective date in this case. MCC states that MPC has known since December 1990 that it would be required to implement FAS 106 for financial reporting purposes on January 1, 1993. MPC's delay in seeking rate relief to cover these costs was entirely within its control.

178. The Commission finds that MPC shall be allowed to recover the amounts deferred. The Commission finds that it is appropriate to use the same amortization period that is used in the FAS 106 accrual calculation. Therefore, MPC's request to amortize the deferral over 18.75 years is denied. MPC shall use a 20 year period to amortize the deferral.

Remaining OPEB Issues

179. MPC's proposal to implement FAS 106 specifically excluded medical and life insurance benefits for current retirees and medical insurance for key employees. MPC proposed remaining on PAYG for these benefits, stating that the total liability for these benefits is low and/or payments will be received by the employees in the next few years. (MPC Exh. 15, pp. 10-11) The Commission accepts MPC's proposal to remain on PAYG for these benefits.

180. Mr. Miller testified that MPC will fund the entire amount of the expense computed in accordance with FAS 106 to the extent that funded amounts can be deducted for state and federal income tax purposes. He stated that securing tax benefits helps to hold down the costs of adopting FAS 106. In this Docket the entire FAS 106 accrual is tax deductible. However, if funding restrictions arise, Mr. Miller proposed to track unfunded amounts and treat the balance as customer contributed capital in the next rate case. (MPC Exh. 15, pp. 4-6, 12)

181. Acknowledging that tax benefits reduce the costs of adopting FAS 106, the Commission finds that MPC shall be allowed to recover amounts equivalent to the level of funding that is tax deductible. That is, MPC shall be allowed to recover in rates the amount of the OPEB expense that can receive tax-advantaged

treatment.

182. The Commission denies MPC's request to track unfunded amounts resulting from funding restrictions that may occur in the future. Such an event has not happened and may never happen.

183. The Commission finds that funding, equal to the amount received through rates, and the use of a tax-advantaged trust are mandatory. All funds recovered in rates shall be deposited into an external trust and receive tax-advantaged treatment. The trust shall restrict the use of these funds exclusively for the payment of OPEB benefits.

184. MPC intends to use both a Voluntary Employees' Beneficiary Association (VEBA) and a Retiree Medical Account within a Pension Plan as funding vehicles. MPC will use the Northern Trust Company as trustee for the Retiree Medical Account. MPC has not yet determined the trustee for the VEBA trust, but has indicated in response to PSC Data Request No. 7 that the trustee will be an independent third party. The Commission accepts MPC's choices.

185. MPC indicated in response to PSC Data Request No. 7 that the trusts to be established for the Utility Division, Colstrip Unit No. 4 and Continental Energy Services will not include a separate sub-account for the Utility Division. Mr. Miller testified at the hearing that a method similar to that used for the pension account would be used to allocate amounts between the participating entities. (Tr. pp. 325-326)

186. The Commission finds that a method similar to that used for pensions is acceptable if all entities have provided funding on an equal basis. To the extent that the other entities (Colstrip Unit No. 4 and Continental Energy Services) do not fund FAS 106 costs or do not fund their proportionate share, MPC shall formulate a calculation to ensure that benefits derived from funding are allocated in a manner consistent with the amount of funding actually completed by each entity.

187. Cost containment measures previously implemented by MPC were discussed in PSC Data Request No. 13. The Commission expects MPC to continue to control the costs associated with OPEBs. Due to the $3 cap placed on medical benefits for retirees over age 65, the Commission recognizes that for all practical

purposes cost containment measures would be limited to life insurance benefits and the benefits payable from the date of retirement to age 65.

188. The OPEB issue reviewed in this Docket was limited to the question of whether to allow a change from the PAYG method to the FAS 106 method. The Commission has not reviewed the level of benefits or the benefit programs offered by MPC. The Commission may review the level of OPEBs and the OPEB programs offered by MPC in future dockets.

189. The Commission emphasizes that the conclusions reached in this Docket pertaining to OPEB apply singly to MPC. In the future the Commission will review each utility on a case-by-case basis, because of the rapidly changing health care environment, the different OPEB plans, and the varying internal practices of utility management, including management decisions to control these costs now and in the future.

190. The revenue requirement effect in this Docket of approving the change to the FAS 106 method, with the modifications made by the Commission, is an increase of $1,002,591 for the Electric Utility and an increase of $321,887 for the Gas Utility.

Captive Coal

191. The issue of the appropriate level of coal expense is contested by MPC and MCC. MPC provided direct and rebuttal testimony from four witnesses on the captive coal issue: Mr. Gannon; Mr. Pederson; and Drs. Landon and Berkman. MCC presented response testimony on the captive coal adjustment from two witnesses: David Kirby and John Wilson.

192. Mr. Gannon noted that if the same captive coal methodology from Docket No. 90.6.39 were applied in this Docket, there would be a coal cost disallowance of over $7 million dollars. That is approximately two and one-half times the $2,679,000 disallowance ordered in Docket No. 90.6.39. The Utility's coal expenses and the amount of coal purchased in the 1992 test year are almost identical to the amounts in Docket No. 90.6.39. The coal supply agreements in place between the Utility and Western Energy Company (WECO) in Docket No. 90.6.39 are the same agreements in place in the 1992 test period.

193. Mr. Gannon provided a history of the captive coal adjustment and explained how the testimony in this case differs from previous cases. Drs. Landon and Berkman, economists with National Economic Research Associates (NERA), jointly sponsored testimony which maintained that the rate of return approach produces arbitrary results.

194. According to Mr. Gannon, the Landon/Berkman testimony showed that coal companies' profits are unrelated to a reasonable price of coal. He asserted that without the relationship to price, a finding of "reasonable profits" is just an averaging of profits from a manipulable set of coal companies and indicates nothing about a reasonable profit level for a particular coal company. Further, he maintained that comparing rates of return on equity for nonregulated companies to determine the "reasonable profit" of coal companies produces arbitrary results. Mr. Gannon referred to several articles written since 1983 and cited by Drs. Landon and Berkman as new information, developed since the last time the Commission heard the captive coal issue. MPC argued that based on the market price approach performed by Drs. Landon and Berkman, no adjustment to MPC's coal cost is necessary.

195. Drs. Landon and Berkman stated: "[i]n practice rate of return is not well regarded as an indication of market power." (MPC Exh. No. 28, p. 15, line 7) The Drs. quote from Market Power and Economic Welfare, by William G. Shepherd: "Altogether, profitability is a treacherous hunting ground for evidence about performance; it is subtle in concept, difficult to measure and ambiguous to interpret." (MPC Exh. No. 28, p. 15, line 22) However, Dr. Berkman is on treacherous ground in attempting to bolster his arguments by quoting Dr. Shepherd. In response testimony Dr. Wilson pointed out that Professor Shepherd has explicitly addressed the issue of whether rate of return is a well regarded indication of market power in The Economics of Industrial Organization, Prentice Hall Inc., Englewood Cliffs, New Jersey, 1985. In summary, Professor Shepherd stated:

> "Market share is strongly associated with profit rates.... Especially for market shares above 20 percent, market power and not economies of scale are usually the reason for

> higher profits. There is probably a strong effect of market power on profitability, just as theory and business experience have always indicated." (p. 130)

196. Dr. Wilson claimed that Drs. Landon and Berkman misunderstood Professor Shepherd's views on this matter. In their rebuttal testimony (MPC Exh. 29), Drs. Landon and Berkman defended their use of Professor Shepherd, noting that a careful reading of the preceding quote reveals that it has nothing to do with rate of return. They maintained that Professor Shepherd referred to market share as an indicator of market power, not rate of return. At the hearing Dr. Berkman had several corrections to his testimony, including deleting from line 30 on page 16 to line 9 on page 17 of MPC Exhibit 29. During cross-examination, Dr. Berkman was asked about that deletion:

Q. During your opening statement you deleted testimony at pages 16 and 17 that had to do with the statements of Professor Shepherd; is that right?

A. Yes.

Q. Can you tell me why?

A. Yes. I, in writing that, had just received Dr. Shepherd's most recent book and, admittedly, read it quickly because we had to file. The passages that I read led me to believe that Dr. Shepherd's opinion was somewhat different from what Dr. Wilson suggests. But since filing, I have had time to read Dr. Shepherd's book more carefully and I concluded that, in that instance, I believe, that Dr. Wilson accurately characterized Professor Shepherd's position. (Tr. pp. 582-583)

The Commission notes the persistence displayed by this witness in the face of contrary evidence and fails to find the witness credible.

197. Mr. Gannon noted that recently a government agency (the Materials Management Service, Royalty Management Program, United States Department of the Interior) reviewed the Colstrip 1 & 2 and the Colstrip 3 & 4 transactions and determined that the contracts are arm's length agreements and the contract prices are competitive. Dr. Wilson's response testimony indicated that the

U. S. Department of Interior Minerals Management Service was addressing whether the federal government is getting a sufficient royalty on the federal coal lease. Since the royalty is a percentage of the coal price, the government wants to be sure that the price for affiliated coal sales is not a "sweetheart" deal that deprives the government of its royalties. The Commission agrees with Dr. Wilson that this is quite different from concluding that MPC's ratepayers were adequately protected.

198. Mr. Pederson described the financial changes which have occurred at WECO since Docket No. 90.6.39. During 1991 and 1992, WECO declared dividends to its parent company Entech, resulting in a reduction of WECO's retained earnings of approximately $146 million. Previously, WECO had invested directly in other Entech companies through advances and notes, rather than providing dividends to its parent company for reinvestment. These advances and notes receivables were a large portion of the assets paid as dividends to Entech in 1991.

199. Prior to the reorganization WECO had three wholly owned subsidiaries: Northwestern Resources Company (Northwestern), which holds coal and lignite leases in Texas and Wyoming and operates the Jewett Mine in Texas; Western Syncoal Company (Syncoal), 50 percent partner of a coal enhancement demonstration plant at the Rosebud Mine in Colstrip, Montana; and Montana Participacoes Limitada (MPL), which owns a 16 percent interest in a gold mine in Central Brazil.

200. In December 1991, the Board of Directors of Entech approved a plan to reorganize the corporate structure of WECO. During 1992, WECO transferred its ownership interest in Northwestern to Entech and is in the process of transferring the ownership of MPL to Entech.

201. The changes at WECO were part of an overall mining division reorganization. The reorganized division has five operating companies, including Horizon Coal Service, Inc., a newly formed marketing and business development company; WECO; Northwestern Resources Company; Basin Resources, Inc., which operates an underground mine in Colorado; and Syncoal. According to Mr. Pederson, Entech did not consider the effect of this dividending and reorganization on MPC's Electric Utility

affiliated coal cost disallowance.

202. Mr. Pederson noted that as a result of the reorganization, WECO's shareholder's equity has substantially decreased, which decreased the amount of the allowed return and increased the magnitude of the captive coal adjustment. This amount increased substantially due to changes in WECO's retained earnings, while the number of tons of coal and the test period fuel expense have not materially changed since the inclusion of Colstrip 3 in Docket No. 84.11.71. Mr. Pederson felt that using the methodology from Docket No. 90.6.39 would produce unreasonable results.

203. Mr. Kirby recommended that the Commission disallow $7,027,675 of MPC's coal expense paid to the Company's affiliated coal supplier WECO. Mr. Kirby noted that after the reorganization WECO is a smaller company, but is more nearly a pure Colstrip coal mining operation. In fact, the financial statements of WECO now more accurately reflect the excess profits WECO earned from its Colstrip mine than was the case before the restructuring. Removal of the dividended assets and the equity that supported them reveals rather than distorts the true rate of return on WECO's sales of Colstrip coal to its affiliate MPC.

204. In addition, Mr. Kirby noted that Mr. Pederson's calculations showed a $6,587,000 increase in WECO's earnings in this case compared to the last case. MPC's calculations reflect WECO's booked results adjusted to remove the impact of non-Colstrip related subsidiaries. Therefore, the earnings increase is attributable to increased profitability of the Colstrip operation. This increase in earnings also contributes to the increase in the captive coal adjustment in this case.

205. Mr. Kirby concluded that the restructuring of WECO makes the captive coal adjustment more accurate. He stated that in past cases the Commission could reasonably have eliminated these non-Colstrip assets and the capital supporting them from the WECO booked financial results before calculating the disallowance. Mr. Kirby saw no persuasive reason, based on the evidence supplied by MPC, to depart from the Commission approved methodology in this or future cases.

206. Dr. Wilson, the other MCC witness on coal expense in

this Docket, explained why the Commission should be concerned about transactions between MPC and its affiliated coal company WECO. The vertical integration by MPC into the coal mining business provides the Company with an opportunity to circumvent effective regulation. MPC is in a position to capture monopoly profits through its affiliated upstream coal business. MPC's electric generating and distribution operations are subject to rate of return regulation. Without an adjustment for excess returns realized on coal purchases from its own affiliate, MPC would be able to achieve excess profits through captive coal transactions. By arranging for highly profitable coal purchase deals with its own affiliate, MPC could raise its regulated accounting costs above the level allowed if the entire integrated operation were permitted only a fair rate of return, resulting in electricity prices higher than would be charged under a cost-of-service standard. The regulatory solution, for ratemaking purposes, is to adjust the utility's cost of service downward for the amount of excess profits earned by the unregulated coal company affiliate.

207. Dr. Wilson examined returns on common equity capital earned from 1987 to 1992 by firms in the fuel industries. Except for 1987, when profits were depressed, the average return for these companies has been in the 9 to 12 percent range. Since WECO is virtually 100 percent equity-financed, he maintained that it would be reasonable to provide a somewhat lower equity return allowance than the cost of capital for a coal company with a leveraged capital structure. It would also be reasonable to provide a relatively low rate of return allowance in this case due to the very low risk nature of WECO's captive coal sales to MPC and its generating partners. Dr. Wilson recommended using an 11.5 percent return in calculating allowable coal purchase costs for ratemaking purposes, or the same return allowed in Docket No. 90.6.39. Since that time, capital costs have continued to decline in the U.S. economy. Consequently, 11.5 percent continues to be more than adequate under prevailing capital cost conditions. WECO's all-equity capital structure results in the lowest possible financial risk.

208. Mr. Pederson in rebuttal noted that WECO is a wholly-

owned subsidiary of Entech. If that were not the case, a substantial portion of the $146 million would not have been dividended. As of December 31, 1992, WECO had a liability on its books of over $80 million for accrued reclamation costs. The $80 million accrued is related to coal mined through 1992; the total liability for mine closings will be about $190 million in current dollars. Except for the parent/subsidiary relationship, at least the $80 million could not have been responsibly dividended. Instead, WECO would have to retain assets to provide assurance that it could meet its reclamation liability. If the $80 million were added back to the equity-financed earnings base, the captive coal adjustment would be reduced from $7,027,675 to $4,621,710. During the hearing MCC asked Mr. Pederson several questions about the $80 million dollars which will be needed for reclamation costs:

> Q. If Western Energy's assets were increased by $80 million, isn't it reasonable to assume that some return would be earned on those additional assets?
>
> A. I think that hopefully we would make fairly decent investment decisions and there would be. I think I responded in the data request exactly in that way.
>
> Q. Yes, you did. And so if you increase the earnings base denominator to account for additional hypothetical assets held by Western Energy, isn't it reasonable to increase the numerator by the amount of the earnings in the hypothetical assets?
>
> A. If you are going to make an adjustment, that would be a reasonable thing to do, yes. (Tr. pp. 553-554)

Mr. Pederson failed to include earnings on the $80 million dollars of assets which he stated WECO needs for reclamation expenses. Additionally, MCC noted that WECO's 1992 balance sheet showed that WECO has more than enough resources to pay all of its liabilities, including reclamation costs, without the additional $80 million which Mr. Pederson said would be needed for a stand-alone WECO. The Commission finds that the $80 million reclamation issue as argued by MPC does not establish that the captive coal methodology is overstated in this Docket. MPC failed to include earnings, which is inappropriate. More importantly, WECO's financial statements show that the Company has more than sufficient assets to pay all of its liabilities.

209. In rebuttal Mr. Pederson noted that the pro forma portion of the adjustment is calculated by applying the change in the Consumer Price Index to certain contract factors in the coal contracts, multiplied by the number of tons of coal in the test period. The contract for purchases of coal at the Corette Plant no longer includes this contract factor. The pro forma piece of the captive coal adjustment totals $75,821, of which the Corette portion is $15,474. During the hearing staff asked Mr. Kirby about this issue:

> Q. The contract for purchases of coal at the Corette plant no longer includes this contract factor. Mr. Pederson identifies the Corette portion of the calculation to be $15,474. Do you agree that the captive coal adjustment should be reduced by that amount?
>
> A. It should be made consistent with the Company's contracts and how the coal expense is treated in the rate case as a whole, but I have not attempted to calculate exactly what that number would be. I'm not aware that there is anything wrong with his figure. (Tr. p. 666)

The Commission finds that the captive coal adjustment should be reduced by $15,474 pursuant to the rebuttal testimony of Mr. Pederson and the cross-examination of Mr. Kirby at the hearing.

210. At the hearing staff questioned Mr. Pederson on his interpretation of how Pacificorp (PP&L) recently treated some of its coal operations. Specifically, PP&L approved a transfer of Bridger and Glenrock coal mining properties into the Company's electric utility operations. He testified that MPC has not planned to do the same, although he admitted that MPC wondered whether it should consider doing so. He stated that he could not

understand how one could figure out how a coal mine that sells 80 percent of the coal outside the utility could allocate some portion to the utility. He believed, therefore, that it would not be a "correct thing for [MPC] to consider," but would be open to a presentation that would make sense. (Tr. pp. 558-559) Dr. Landon also made it sound as though cost allocations for the coal mining operations would be so complex as to be beyond the limits of possibility.

211. Dr. Wilson addressed the allocation of coal sales during his cross-examination. He testified that there was not a difficult allocation problem. WECO basically has undivided interests in a coal supply which can be allocated on a straightforward percentage basis. He recommended that the Commission recognize the pro rata share attributable to MPC's purchases from the coal mine, determine the profitability attributable to that purchase/sale, and then decide the rate of return appropriate for the transaction, for ratemaking purposes. (Tr. pp. 642-644) The Commission agrees with Dr. Wilson that allocations related to WECO for sales made to MPC are the types of allocations made routinely in regulation. The Commission does not agree with Mr. Pederson on the issue of allocating costs between coal supplied by WECO to MPC and coal sold by WECO to other third parties. Cost allocations are a standard part of utility ratemaking.

Commission Decision

212. The methodology of the captive coal adjustment in this case is identical to that used in the last case. The adjustment is over two times greater than in the last case, primarily as a result of the reorganization of WECO. Another factor increasing the adjustment in this case is an increase in earnings at WECO of $6,587,000 since the last case. The parent corporation MPC (as opposed to the utility) undertook the reorganization fully knowing the effect that reorganization would have on the captive coal adjustment in a future rate case. Armed with that knowledge, the Company proceeded to reorganize. The Commission agrees with Mr. Kirby that the reorganization of WECO means that the Company is smaller but more nearly a pure Colstrip mining operation. In retrospect, it would appear that the captive coal

adjustment was grossly understated in past cases. MPC presented compelling evidence of WECO's past profitability when it indicated that $146,000,000 was paid as dividends by WECO to Entech.

213. The Commission finds that the testimony of Dr. Wilson is persuasive as to the market price testimony of Drs. Landon and Berkman. The Commission determines that in this case it should continue to apply the rate of return methodology used for over a decade. Particularly, the history of the coal mines and the location of the coal plants firmly support this captive coal adjustment.

214. Drs. Landon and Berkman cite a number of articles in favor of a market price analysis. Yet, only three states use such a method, West Virginia, Pennsylvania and Ohio. Any method to evaluate excess profits presents difficulties. However, contrary to Drs. Landon and Berkman, the Commission finds that the rate of return method is appropriate to ensure that ratepayers are charged a reasonable cost for coal. The Commission was not persuaded by the arguments of Drs. Landon and Berkman that market price analysis should be used. The rate of return methodology is used in virtually every utility rate case to determine the cost of capital.

215. It is impossible to reconcile the positions taken by MPC's coal witnesses with that of MPC's cost of capital witness, Dr. Olson. The coal contracts established for the Colstrip plants were not established in a competitive environment. Drs. Landon and Berkman relied on two 1977 and 1978 federal government studies to support their contention that western coal markets are competitive. At the hearing, they agreed that those studies did not claim that a competitive coal market existed in 1970. The decision to build Colstrip Units 1 & 2 as mine mouth plants was made prior to the 1977 and 1978 studies. (Tr. p. 568)

216. The boilers for these generating stations were specifically designed to burn coal from the coal mines at Colstrip. The testimony of Drs. Landon and Berkman did not remove the concerns the Commission has with the market price methodology. As in past cases, the Commission finds that the sale of coal from WECO to MPC is an affiliated transaction which

is not at arm's length. As such, the Commission finds that the captive coal methodology based upon rate of return is appropriate.

217. The Commission agrees with Dr. Wilson that the 11.5 percent rate of return from Docket No. 90.6.39 is still reasonable in light of the rapid decline in the cost of capital since that case. The Commission finds that coal expense should be reduced by $7,012,201.

ADDITIONAL ISSUES

Top Layer Coal Supply Blending for Colstrip Units 3 and 4

218. The Commission identified this issue in a Notice of Commission Action dated September 20, 1993. The Commission attached to this Notice excerpts from two reports completed for Colstrip 3 and 4 owners by Marston and Marston, Inc., pertaining to the WECO coal supply used for Colstrip 3 and 4 generation facilities. The Marston study particularly questioned WECO's practice of providing the top 6" to 12" of the coal seam (soft layer) to the Montana One Qualifying Facility (QF) at low or no cost, when it may be possible to blend it with the rest of the Colstrip 3 and 4 coal.

219. The Marston reports were dated April 25, 1991, and July 21, 1993. The Commission then asked the parties to comment on whether the Commission could, for ratemaking purposes, use the conclusions from the first Marston report on the BTU and sulfur content of the coal to increase the captive coal adjustment under the assumption that Montana One would pay more for the coal it receives if it were made aware of the value of the coal to the Colstrip 3 and 4 owners.

220. The Commission, in view of the significance of coal expenses for Colstrip 3 and 4 totalling $90,185,503 for 1992, also asked the parties to draw conclusions from the two-year passage of time between the two Marston reports which contained essentially the same conclusion: "A study of 'QF' coal should be undertaken to determine if it can become part of the coal order for Units 3 and 4." The successful burning of 'QF' coal could represent fuel cost savings to the owners.

221. Mr. Pascoe stated that the Commission appeared to be asking two distinct questions about this issue. First, was there

some opportunity for the Colstrip 3 and 4 owners to lower their fuel costs by burning the top 6" to 12" of the coal seam currently being treated as waste? Second, was there a connection between the compensation WECO received for the waste coal and the captive coal adjustment?

222. According to Mr. Pascoe, for a period of time in the 1970's the entire coal seam, including what is now considered to be the waste coal, was mined and delivered to Colstrip 1 and 2 and other WECO customers. During this period, Colstrip 1 and 2 experienced operational problems, such as increased boiler slagging and difficulties meeting air emission standards. Mr. Pascoe testified that WECO's other customers in the Midwest also expressed concerns about coal quality during this period. To mitigate these coal quality concerns, the burning of the top layer of the coal seam ceased, and no WECO customer, with the exception of Montana One, has burned the top layer of the coal seam since these mining practices went into effect.

223. Mr. Pascoe testified that the Marston report reached no conclusions about this matter. Marston merely recommended further study of this possibility. According to Mr. Pascoe, even if one were to assume that the waste coal could be successfully burned, "significant" cost savings would not result.

224. First, the owners would have to purchase the waste coal under the terms of the Colstrip 3 and 4 Coal Supply Agreement and pay to have it delivered to the plants under the Colstrip 3 and 4 Coal Transportation Agreement. Therefore, according to Mr. Pascoe, it would appear that the effective net price per ton of the waste coal would be only slightly less than the price now paid for coal delivered to Colstrip 3 and 4.

225. Mr. Pascoe testified that if the entire coal seam could be successfully burned, the "mixed" coal would be higher in sulfur content, requiring an increase in lime consumption in the scrubbers. The "mixed" coal would also be higher in ash content, increasing costs for ash handling and disposal with a potentially negative impact on the plants' heat rate. The "mixed" coal would also have a lower BTU content leading to an increase in the tons of coal burned to produce a given amount of gross generator output. This increased coal throughput would require increased

operation of coal mills, fans, scrubbers and other auxiliary equipment. Increased operation of this equipment would consume electrical output from the generators, reducing the net output of the plants, as well as causing increased maintenance expenses. All of these operational impacts would offset, probably entirely, any fuel savings which might be available by burning the waste coal, according to Mr. Pascoe.

226. Mr. Pascoe testified that the captive coal adjustment is based on the premise that MPC is paying too much for its affiliated coal purchases from WECO. Mr. Pascoe stated "In this instance the Commission appears to be concerned about a transaction between WECO and Montana One, two unaffiliated entities whose profits are not subject to the Commission's jurisdiction."

227. Finally, Mr. Pascoe noted that neither of the Marston reports concluded that the waste coal can be mined with the balance of the coal seam and successfully burned in Colstrip 3 and 4. These reports suggested this possibility and recommended further study of this issue. There is not enough factual information available about this issue to conclude that an adjustment is warranted or to provide the basis for the calculation of such an adjustment.

228. Mr. Kirby, in response testimony, agreed with Mr. Pascoe: "There is not enough factual information available about this issue to conclude that an adjustment is warranted or to provide the basis for the calculation of such an adjustment." Mr. Kirby stated that such an adjustment must be premised on the technical feasibility of burning the waste coal and performing a calculation of the net costs and benefits of doing so. The Marston reports stopped short of asserting that it would in fact be feasible to burn the waste coal, but recommended further study.

229. Mr. Kirby recommended no adjustment in this case. However, he did recommend that the Commission require MPC to support the reasonableness of its coal costs in its next case. If MPC maintains that the waste coal cannot be cost-effectively burned, then it should meet its burden of proof with a study prepared by an independent engineering consulting firm.

Commission Decision

230. MPC has not adequately explained its apparent noncompliance with the Marston recommendation to study the feasibility of burning the waste coal. The 1991 Marston report stated: "Because Western spoils the QF coal if it is not loaded, the QF production should be beneficial to the owners because it should serve to decrease the overall AREA C unit cost of coal per ton produced." Despite this potential cost reduction envisioned in the Marston report, Mr. Pascoe contended that the Colstrip 3 and 4 owners would have to purchase the waste coal under the terms of the Coal Supply Agreement at little or no reduction in price per ton compared to the price now paid for higher grade coal. Here, Mr. Pascoe seems to suggest that WECO would not pass through to its customers the full cost savings it would achieve from mixing the waste coal with the higher grade coal. However, Mr. Pascoe failed to consider that any WECO cost savings not passed through would increase WECO's excess profits, and thus increasing the captive coal adjustment. Under the Commission's captive coal adjustment methodology, any WECO cost savings would benefit ratepayers whether or not it was passed through as lower coal prices to MPC or not.

231. The Commission agrees with the parties that no adjustment for this issue is appropriate in this Docket. However, the Commission directs MPC to undertake an evaluation of the feasibility of burning waste coal at its Colstrip Units 3 and 4 to be conducted by an independent engineering firm. The cost-effectiveness of this alternative should consider all factors, including fuel cost savings as well as all operational impacts from burning waste coal. MPC shall file the results of its evaluation of this issue in its next rate filing. The evaluation should include several test burns to collect the necessary data to complete a thorough evaluation of burning waste coal. Before the next general rate case, MPC shall inform the Commission staff on the status of this engineering study for monitoring purposes.

Other Additional Issues

232. The Commission also identified the following additional issues:

Decoupling - Cost of Capital

Decoupling - Coyle
Decoupling - Energy Service Charge
Decoupling - Off-System Sale
IRS Tax Basis for Colstrip 4
Bond Ratings
CNG
Missoula Watershed
Headquarter Efficiency

The Commission asked parties to address these issues in a Notice of Commission Action dated September 20, 1993. MPC, MCC, Large Customer Group, District XI Human Resource Council, and the Department of Natural Resources and Conservation (DNRC) presented testimony on these issues. With the exception of the Energy Service Charge and Off-System Sale issues which are discussed in another part of this Order, at this time the Commission elects to take no action on these issues.

PSC TAX CHANGE

233. On November 2, 1993, the Commission approved Order No. 5757, (Docket No. 93.10.52), authorizing regulated companies to file tariffs reflecting the increase in PSC tax rates. (On October 1, 1993, the rate increased from .24 percent to .28 percent.) The Commission stated that companies may choose to defer implementing tariffs reflecting the increase until a later date to coincide with other tariff changes, but that the revenue requirement may not be accumulated unless authorized by the Commission. (Order No. 5757, FOF 6) Pursuant to Order No. 5757, MPC filed notice on November 18, 1993, that it requested recovery of the PSC tax increase back to October 1, 1993. On December 2, 1993, the Commission authorized MPC to (1) accumulate the revenue deficiency associated with the PSC tax increase, effective October 1, 1993; and (2) reflect the PSC tax rate in tariffs filed pursuant to a final order in Docket No. 93.6.24.

234. The Commission finds that it is appropriate to reflect both the accumulated amounts and the increase in the PSC tax rate in this Order. The effect on the revenue requirement for inclusion of the accumulated amounts is an increase of $86,550 for the Electric Utility and an increase of $32,328 for the Gas Utility.

INTERPRETIVE CENTER

235. Pursuant to public request the Commission has reviewed the intentions of MPC to spend approximately $1.5 million for the

Lewis and Clark Interpretive Center. The Commission found that this expenditure, which has not yet been paid, is a result of mitigation required by the Federal Energy Regulatory Commission (FERC) for the current relicensing of Missouri/Madison Project No. 2188. MPC is not requesting recovery of this cost in the current rate case. The Commission is precluded from ruling on an issue prior to inclusion in a rate case. When MPC requests recovery, the Commission will make a determination regarding the appropriateness of including this cost in rates.

REVENUE REQUIREMENT - ELECTRIC

236. Based on the above Findings of Fact, the following tables show that an increase in MPC annual electric revenues in the amount of $6,874,092 on a total company basis is necessary in order to provide the opportunity to earn an overall rate of return of 9.09 percent. After performing the REC jurisdictional allocation, the required increase in MPC annual jurisdictional electric revenues is $7,595,458.

THE MONTANA POWER COMPANY – DOCKET 93.6.24
FINAL REVENUE REQUIREMENTS CHART – ELECTRIC
TO PRODUCE 9.09% RATE OF RETURN
TEST YEAR DECEMBER 31, 1992

		(A) MPC ORIGINAL FILING	(B) TOTAL ACCEPTED ADJUSTMENTS	(C) PSC APPROVED PRO FORMA	(D) INCREASE FOR 9.09% RETURN	(E) PSC APPROVED TOTAL	
1							1
2	REVENUE	$404,843,627	$13,497,358	$418,340,985	6,874,092	$425,215,077	2
3							3
4							4
5	COST OF SERVICE						5
6	TOTAL OPERATIONS & MAINTENANCE EXPENSES	$231,669,785	($454,801)	231,214,984		231,214,984	6
7	DEPRECIATION EXPENSES	36,179,267	0	36,179,267		36,179,267	7
8	AMORTIZATION OF COMPUTER SOFTWARE COSTS	672,827	(70,310)	602,517		602,517	8
9	AMORTIZATION KERR LICENSE COST	25,194	0	25,194		25,194	9
10	AMORTIZATION KERR WILDLIFE STUDY	34,339	0	34,339		34,339	10
11	AMORTIZATION PLANT ACQ. ADJ. – MILWAUKEE	94,914	0	94,914		94,914	11
12	AMORTIZATION OF MPSC/FERC PLANT DIFFERENCE	1,458,187	0	1,458,187		1,458,187	12
13	AMORTIZATION OF INVESTMENT TAX CREDIT – NET	(1,563,478)	0	(1,563,478)		(1,563,478)	13
14	PROVISION FOR DEFERRED INCOME TAXES	4,109,535	(627,617)	3,418,918		3,418,918	14
15	TAXES OTHER THAN INCOME TAXES	39,810,311	181,604	39,991,915	21,309	40,013,224	15
16	CORPORATE ENVIRONMENTAL TAX	66,942	16,637	83,579	7,669	91,248	16
17	INCOME TAXES – FEDERAL	15,679,597	5,312,648	20,992,245	2,234,072	23,226,317	17
18	INCOME TAXES – MT CORPORATION LICENSE	3,604,791	736,768	4,341,559	462,045	4,803,604	18
19							19
20	TOTAL COST OF SERVICE	$331,842,211	$5,094,929	$336,937,140	$2,725,095	$339,662,235	20
21							21
22							22
23	UTILITY OPERATING INCOME	$ 73,001,416	$8,402,429	$81,403,845	4,148,997	85,552,842	23
24							24
25							25
26	RATE BASE	$944,885,487	($3,710,164)	$941,175,323		941,175,323	26
27							27
28							28
29	RATE OF RETURN	7.73%		8.65%		9.09%	29
30							30

THE MONTANA POWER COMPANY
ELECTRIC UTILITY
REC SEPARATION
1992 TEST YEAR – OPTIONAL RULES
DOCKET 93.6.24 FINAL ORDER

	Total Electric	MPSC Share	REC Share
RATE BASE	$941,175,323	$903,174,361	$38,000,962
TOTAL WEIGHTED COST OF CAPITAL	9.09%	9.09%	9.09%
RETURN OF RATE BASE	85,552,837	82,098,549	3,454,287
NET OPERATING INCOME	81,403,846	77,514,160	3,889,686
REQUIRED INCREMENTAL INCREASE/DECREASE	4,148,991	4,584,389	(435,398)
ADD INCREMENTAL TAXES:			
ENVIRONMENTAL TAX	7,669	8,474	(805)
MPSC TAX	19,247	21,267	(2,020)
CONSUMER COUNSEL TAX	2,062	2,279	(216)
FEDERAL INCOME TAX	2,234,072	2,468,517	(234,445)
STATE INCOME TAX	452,045	510,532	(48,487)
TOTAL REVENUE INCREASE/DECREASE	$6,874,087	$7,595,458	($721,372)

REVENUE REQUIREMENT - GAS

237. Based on the above Findings of Fact, the following table shows that an increase in MPC's annual gas revenue in the amount of $5,783,972 is necessary in order to provide the opportunity to earn an overall rate of return of 9.49 percent.

THE MONTANA POWER COMPANY – DOCKET 93.6.24
FINAL REVENUE REQUIREMENTS CHART – GAS
TO PRODUCE 9.49% RATE OF RETURN
TEST YEAR DECEMBER 31, 1992

		(A) MPC ORIGINAL FILING	(B) TOTAL ACCEPTED ADJUSTMENTS	(C) PSC APPROVED PRO FORMA	(D) INCREASE FOR 9.49% RETURN	(E) PSC APPROVED TOTAL	
1							1
2	REVENUE	$100,730,601	$1,210,457	$101,941,058	5,783,972	$107,725,030	2
3							3
4							4
5	COST OF SERVICE						5
6	TOTAL OPERATIONS & MAINTENANCE EXPENSES	$55,012,042	$378,614	55,390,656		55,390,656	6
7	DEPRECIATION EXPENSES	8,341,243	0	8,341,243		8,341,243	7
8	AMORTIZATION OF COMPUTER SOFTWARE COSTS	220,367	(24,437)	196,930		196,930	8
9	AMORTIZATION OF INVESTMENT TAX CREDIT – NET	(235,474)	0	(235,474)		(235,474)	9
10	PROVISION FOR DEFERRED INCOME TAXES	1,954,438	(718,551)	1,235,887		1,235,887	10
11	TAXES OTHER THAN INCOME TAXES	12,204,617	72,975	12,277,592	17,930	12,295,522	11
12	CORPORATE ENVIRONMENTAL TAX	18,564	2,306	20,870	6,477	27,347	12
13	INCOME TAXES – FEDERAL	3,797,787	798,002	4,595,789	1,886,774	6,482,563	13
14	INCOME TAXES – CANADIAN TAXES	(200,390)	111,828	(88,562)	0	(88,562)	14
15	INCOME TAXES – CORPORATION LICENSE TAX	766,447	75,929	842,376	368,783	1,211,159	15
16	INCOME TAXES – OTHER STATE TAXES	0	0	0	0	0	16
17							17
18	TOTAL COST OF SERVICE	$ 81,879,641	$697,666	82,577,307	2,279,964	84,857,271	18
19							19
20							20
21	UTILITY OPERATING INCOME	$ 18,850,960	$ 512,791	$19,363,751	3,504,008	22,867,759	21
22							22
23							23
24	RATE BASE	$243,556,167	($2,589,269)	$240,966,898		$240,966,898	24
25							25
26							26
27	RATE OF RETURN	7.74%		8.04%		9.49%	27

DEMAND SIDE MANAGEMENT (DSM) COST RECOVERY

238. On June 21, 1993, Mr. Corcoran filed direct testimony regarding DSM cost recovery which included a proposal to remove the disincentives to invest in DSM and provide for proper cost recovery. He recommended a package that:

a) Provides for timely Rate Basing of DSM investments;
b) Includes AFUCE in order to cover the cost of capital prior to the inclusion of conservation expenditures in rates;
c) Allows Delayed Amortization until the conservation amortization expense can be included in rates;
d) Includes a Lost Revenue Adjustment (Decoupling or Lost Revenue Adjustment Mechanism (LRAM)) to recover the net lost revenues arising from reduced electric sales/revenues due to DSM investments between rate decisions, and;
e) Establishes a Performance Incentive that allows MPC owners and customers to share the DSM benefits.

(MPC Exh. 8, pp. 14-15)

Rate Basing

239. Mr. Corcoran maintained that DSM costs not currently recovered in rates must be included in rate base to allow MPC to earn a return on its DSM investments. Further, he believed that rate basing is allowed in accordance with ARM 38.6.301, Part (1). The total electric rate base associated with DSM investments is $8,038,165, or an increase of $7,384,371 when compared to the test period information in Docket No. 90.6.39 (twelve months ended December 31, 1989). (MPC Exh. 8, pp. 15-16) The total gas rate base associated with DSM investments is $2,502,768.

240. No other parties presented testimony regarding the rate basing of DSM. Further, no evidence was presented to indicate that any of MPC's DSM investments requested in this Docket should be disallowed. The Commission accepts the rate base amounts associated with DSM investments as proposed by MPC.

AFUCE (Allowance for Funds Used for Conservation Expenditures)

241. Mr. Corcoran maintained that AFUCE is necessary to cover the cost of capital prior to the inclusion of conservation expenditures in rates. He believed that AFUCE is allowed in accordance with ARM 38.6.301(2). The total electric AFUCE associated with DSM investments reflected in this filing is $621,372. This amount has increased $621,372 over the test period information in Docket No. 90.6.39 (twelve months ended December 31, 1989). (MPC Exh. 8, p. 16) The total gas AFUCE associated with DSM investments reflected in this filing is $186,611. No other parties presented testimony on AFUCE.

242. ARM 38.6.301(2) states that AFUDC-like carrying charges will be allowed to accrue on deferred balances of conservation investments. (AFUDC = Allowance for Funds Used During Construction) The Commission finds that MPC shall be allowed to recover the AFUCE amounts of $621,372 for the Electric Utility and $186,611 for the Gas Utility.

243. The Commission also finds that MPC's interpretation of "AFUDC-like" carrying charges needs examination. For example, DSM expenditures are cleared to a regulatory asset account at the end of each month. However, even though a ten year amortization begins the following month, AFUCE is calculated on the unamortized balance. (Tr. p. 68) (PSC DR No. 47) Therefore, the Commission finds that MPC shall present testimony in its next general rate case supporting the methods used to calculate AFUCE.

Delayed Amortization

244. Mr. Corcoran stated that current accounting treatment requires that a ten-year amortization of DSM expenditures begin immediately. MPC is requesting delay of amortization of DSM expenditures that occur between rate cases until the following rate case. MPC has maintained that by beginning the amortization immediately, the recovery of incremental amortization expenses occurring between rate cases is lost, creating inequities related to the return of DSM expenditures (amortization expense) in rates. (MPC Exh. 8, pp. 16-17)

245. Dr. John Wilson stated that delayed amortization is not necessary or appropriate under profit decoupling, because profits are held constant and there are opportunities for profit-enhancing conservation initiatives. He also stated that delayed

amortization tends to be inappropriate in other systems as well, since it constitutes a one-sided post test year adjustment. (Response to PSC DR No. 164, Tr. pp. 509-510)

246. The Commission has granted rate basing and AFUCE for DSM investments. Further, the recovery period for conservation expenditures (ten years) is already much shorter than for supply side resources. As discussed in subsequent findings, the issue of lost revenues from DSM is covered in the Decoupling aspect of MPC's request. During the hearing Mr. Corcoran acknowledged that MPC does not use delayed amortization for supply side resources. (Tr. p. 70) In response to MCC Data Request No. 438, MPC witness Cole indicated that AFUCE and rate basing put DSM on the same basis as supply side resources. The Commission notes that Mr. Cole did not state that delayed amortization was needed to put DSM on the same basis as supply side resources. The Commission finds that MPC has not demonstrated why DSM resources should be treated more favorably than other plant assets in terms of delayed amortization. MPC's request for delayed amortization of DSM investments is denied.

Decoupling

247. Mr. Corcoran introduced MPC's proposed decoupling mechanism in prefiled testimony. (MPC Exh. 8) MPC proposed decoupling to address what is called the "lost revenue problem" associated with utility investment in demand-side management. In theory, other things being equal, utility acquisition of demand-side resources rather than supply-side resources reduces the utility's total retail sales of electricity. The Commission designs rates to allow the utility to earn enough revenue each year to cover the embedded cost of supplying a test year level of electricity sales and provide a reasonable profit. If, between rate cases, the utility can reduce its cost of supplying electricity or if the amount of sales is greater than the test year amount, the utility will generally earn greater profits. By reducing total sales, demand-side resource acquisition interferes with the utility's opportunity to earn greater profits between rate cases. This situation could cause inefficient resource allocation, higher costs, higher electric rates and unnecessary environmental degradation because utilities would have the

incentive to forego acquiring cost-effective demand-side resources in order to maintain or increase profits. (Tr. p. 161)

248. In theory, decoupling would remove the connection between the profit the utility has an opportunity to earn between rate cases and the amount of electricity it sells. If the utility knows it cannot increase its profits by selling more electricity and will not lose profits by selling less electricity, the incentive to forego cost-effective demand-side resource acquisition should largely be removed. Supporters state that decoupling preserves the current regulatory structure with respect to other risks and incentives. For example, decoupling, as proposed, retains the incentive for the utility to reduce costs and increase productivity and does not shift the risks associated with changing weather and economic conditions from the utility to ratepayers. (MPC Exh. 8, p. 34-35, HRC Exh. 1, p. 19-23, Tr. p. 137)

249. The decoupling mechanism proposed by MPC includes three components: (1) a forecast of retail kwh sales (the index); (2) actual, weather normalized retail kwh sales; and (3) the incremental fixed cost margin for retail kwh sales. The incremental fixed cost margin represents the amount of money the Company foregoes if a kwh sale is not made. It is calculated by subtracting the variable costs, which the Company no longer incurs when a kwh sale is not made, from the average retail price charged per kwh. The incremental fixed cost margin is multiplied by the difference between an estimate of what MPC would have sold if it had not acquired any DSM (i.e., the forecast kwh sales) and what the Company actually did sell, normalized for weather. What results is the decoupling adjustment. In mathematical form, the decoupling adjustment is expressed as follows:

Decoupling Equation
Decoupling Adjustment = [F(Qs) - A(Qs,wn)] * I(Fk) where

F(Qs) = Forecast retail kwh sales without DSM (the index)
A(Qs,wn) = Actual, weather normalized kwh sales
I(Fk) = Incremental fixed cost margin per kwh sale

250. Proponents of decoupling testified that the use of weather normalized actual sales and an index incorporating expected future economic conditions means that the proposed

decoupling adjustment would not shift the risk of changes in weather or the economy from MPC to ratepayers (MPC Exh. 8, pp. 34-35 and HRC Exh. 1, pp. 19-23). Although parties recognize that an index based on a utility forecast of kwh sales could be manipulated by the utility, testimony suggests that risk would not exist for the current forecast because that forecast was not developed for decoupling purposes. (Tr. p. 515)

251. MPC proposed annual filings to recover the decoupling adjustment in rates over the subsequent year. The adjustment would be collected through a uniform percentage adjustment to all customers' rates.

252. MPC proposed a decoupling adjustment band that limits the size of the adjustment. A decoupling adjustment requiring a revenue increase greater than 4 percent or a revenue decrease greater than 1 percent of MPC's then current fixed cost revenues would trigger a hearing to determine why the adjustment was outside the band and whether the Company should be entitled to recover the amount outside the band.

253. HRC and LCG testified that MPC should disaggregate the decoupling mechanism by rate class, using rate-class-specific energy forecasts, actual sales and incremental fixed cost margins to calculate the decoupling adjustment. Disaggregating by class would recognize that different classes have different fixed cost margins built into their rates, which causes a DSM related reduction in sales to one customer class to have a different impact on the utility's profits than a reduction in sales to another customer class. In rebuttal, MPC agreed that this adjustment should be made to its decoupling mechanism. (HRC Exh. 1, p. 35, and MPC Exh. 9, p. 15)

254. HRC and LCG also testified that MPC should remove the revenues obtained from customer charges from the revenues used to calculate the decoupling adjustment. Customer charge revenues are recovered by MPC regardless of decreases in kwh sales. Therefore, the decoupling adjustment should not include this portion of the fixed costs. (HRC Exh. 1, p. 36 and MPC Exh. 9, p. 15)

Decoupling Stipulation

255. MPC introduced a stipulation agreement between MPC,

MCC, HRC, Northern Plains Resource Council, Montana Environmental Information Center (MEIC), DNRC and the Natural Resource Defense Council which sets forth a decoupling proposal in this case. (MPC Exh. 1) The other intervenor in this case, LCG, did not sign the stipulation

256. The stipulated decoupling proposal is based on a four year trial period. For the first two years, the decoupling index would be the forecast kwh sales contained in MPC's March 1993 Load Forecast and Integrated Least Cost Plan. The stipulating parties agree to study alternative decoupling indexes for possible use during the last two years of the trial period. In addition, for the first two years, the latest test year short-term purchase power price would be used as the variable cost off-set when calculating the incremental fixed cost margin. The stipulating parties agree to work on the appropriate identification and definition of the variable cost component used as the off-set.

257. The stipulated decoupling mechanism would calculate the decoupling adjustment on a disaggregated class basis and would exclude the customer charge revenues. The parties agree that the decoupling adjustment should be set at 90 percent of MPC's proposed formula result (see the Decoupling Equation in FOF 249) for the first two years of the trial period. The parties also agree that the adjustment band proposed by MPC is appropriate.

258. As stipulated, MPC would prepare annual reports for use in evaluating the effectiveness of decoupling compared to the status-quo. The reports would address such areas as lost revenue recovery, risk shifting, MPC support for DSM and MPC marketing activities. The parties also agree to meet on a regular basis in order to monitor and evaluate the decoupling experiment. The stipulation provides that the meetings will be conducted as a sub-group of MPC's least cost planning advisory committee. (MPC Exh. 1, paragraphs 4 and 6)

259. Finally, the stipulation states that MPC, DNRC and other interested parties will work together to fully develop a customer service charge alternative to decoupling. The stipulation states that, unless the parties agree otherwise, MPC would propose a customer service charge experiment for Commission

approval within one year of the date of the final order in Docket No. 93.6.24.

260. LCG is the only intervening party not to sign the decoupling stipulation agreement with MPC. LCG opposed decoupling and recommended that the Commission reject the proposal. LCG testified that there are many potential problems with decoupling. LCG believes decoupling will cause prices to move in the opposite direction from what they would under competition. (LCG Exh. 1, p. 14) LCG posed a hypothetical situation where an economic downturn causes kwh sales to decrease, in turn resulting in a positive decoupling adjustment and a rate increase. Utility customers already facing economic hardship are then asked to insulate the utility from this same hardship.

261. LCG also argued that decoupling may cause gaming of expenses, mis-identification of fixed and variable accounts and public confusion. LCG is not convinced that decoupling will significantly increase DSM acquisition, citing MPC's March 1993 least cost plan which indicates that the Company's DSM acquisition is driven by uncertainty in forecasting the quantity, price and rate of DSM acquisition, not lost revenues. (LCG Exh. 1, p. 15 and Tr. p. 213)

262. LCG claimed that implementing decoupling would shift risks due to economic fluctuations, population changes, price responses and income changes from MPC to ratepayers. (LCG Exh. 1. pp. 16-17)

263. Finally, LCG asserted that no one has shown that the problem which decoupling is proposed to solve is really a problem, nor established a cause and effect relationship between MPC acquisition of DSM and recovery of lost revenues. (LCG Exh. 3, p. 3, PSC DR No. 192) LCG further asserted that the standards for determining the success or failure of decoupling are not adequately defined. LCG testified that these standards should be well defined before beginning a decoupling experiment. (Tr. p. 216)

Commission Decision

264. The Commission understands that once decoupling begins, we cannot know what would have been the status-quo without

decoupling. Therefore, approving decoupling for a four-year trial period means we will never know with certainty whether MPC's actions without decoupling would have been significantly different. However, if MPC is concerned about lost revenues and if decoupling alleviates that concern, then the Commission would expect after approving decoupling to observe a marked change in the MPC approach to cost-effective demand-side resource acquisition.

265. The decoupling stipulation provides a reasonable way to test the concept of decoupling as a means of improving the efficient acquisition of cost-effective DSM. Therefore, the Commission adopts the decoupling stipulation in this case. However, the Commission finds that the stipulation's provisions related to monitoring and evaluating the success of decoupling are weak. Therefore, while the provisions in the decoupling stipulation provide a starting point, MPC is directed to further develop meaningful tests with which to evaluate decoupling over the four-year trial period.

Performance Incentive

266. MPC proposed an incentive mechanism which it maintained would provide the Company with an additional incentive to exceed its DSM program levels. MPC characterized its proposal as a shared savings approach that allows the stockholders and ratepayers to share the net savings attributable to the DSM programs. Net savings would be calculated by taking the difference between the avoided cost of the DSM resource and the actual utility cost of the program. If MPC meets the DSM levels included in its latest resource plan, it proposes that 80 percent of the savings go to ratepayers and 20 percent to stockholders. If MPC does not meet these levels of savings but there are still positive savings, it proposes a 90 percent/ 10 percent split. If there are no positive net savings, MPC would be assessed a 20 percent penalty.

267. MPC testified that its performance incentive proposal would provide three specific incentives: (1) an incentive to meet MPC's resource plan DSM program levels; (2) an incentive to keep DSM program costs low; and (3) an incentive to pursue DSM programs with positive net savings. (MPC Exh. 8, p. 43)

268. MPC testified that DSM incentives are needed to balance market and institutional barriers associated with DSM, including uncertainty about the long-term reliability of DSM, lack of resource control and dispatchability, and the risk of DSM as a regulatory asset. Mr. Houser testified that MPC does not have a long track record with DSM. The lack of documented performance over a long period of time increases the uncertainty relative to DSM resources, in turn contributing to institutional barriers that MPC believes can be partially addressed with a performance incentive. (Tr. p. 113)

269. MPC's performance incentive proposal was not well-received by intervenors. DNRC testified that it supports an experiment in a portion of MPC's service area. MCC opposed the proposal, asserting that MPC's biggest incentive would be to inflate estimates of DSM savings (MCC Exh. 4, p. 55). LCG testified that the proposed incentive is based on engineering estimates of DSM savings, which puts ratepayers at risk if the measures do not perform as expected. (LCG Exh. 1, p. 26) LCG stated that a significant portion of any incentive should be withheld until MPC has evaluated actual savings. HRC did not testify on the performance incentive and MEIC testified that MPC's least cost planning advisory committee should discuss the issue of incentives before the Commission allows the proposal.

Commission Decision

270. The Commission denies MPC's performance incentive proposal. The record lacks sufficient support to grant the proposal. In addition, the Commission finds that the proposed performance incentive would require detailed information about the actual savings associated with DSM programs in order to compute an accurate net savings value. This information is not currently available. Finally, the Commission finds that simultaneously approving a performance incentive and decoupling could interfere with the evaluation of decoupling; it would be difficult to determine whether any change in DSM acquisition is a result of decoupling or the performance incentive. Therefore, in order to allow for an unbiased decoupling experiment, the Commission finds that the performance incentive should not be approved.

DSM Cost-Effectiveness

271. Several parties testified concerning DSM cost-effectiveness. LCG testified that the Commission should further review MPC's E+ programs before allowing full cost recovery in rates. (LCG Exh. 1, p. 2) LCG asserted that acquiring DSM is like acquiring any other resource such as a hydro upgrade or purchased power and that ratepayers should know what they are receiving when they purchase DSM. LCG testified that MPC has shown the program costs for its E+ resources but has not similarly shown the benefits (e.g., energy savings) associated with these resources. (LCG Exh. 1, p. 5) LCG witness Iverson recommended that the Commission "...establish a procedure or mechanism by which the benefits and energy savings associated with MPC's E Plus conservation programs can be quantified and substantiated." (Tr. p. 219) Under cross examination, Ms. Iverson stated that "we don't have a clear-cut definition of what constitutes cost-effective DSM for Montana Power Company right now." (Tr. p. 245)

272. DNRC testified that abundant literature suggests that engineering estimates grossly overstate the performance of DSM in practice and that utilities commonly understate the total costs of DSM programs. (DNRC Exh. 1, p. 27) According to DNRC, the literature implies that the cost-effectiveness of DSM is lower than commonly thought. DNRC recommended that the Commission order MPC to produce a thorough review of the cost-effectiveness of its DSM programs and the measures included in those programs. DNRC stated that it is not completely satisfied with MPC's use of engineering analyses to construct DSM programs and estimate their effectiveness. DNRC testified that "...the most important issue for the Commission to deal with is to insist that MPC move on to statistical analysis and verification." (DNRC Exh. 1, p. 29)

273. In Final Order No. 5360d in Docket No. 88.6.15, the Commission addressed the issue of conservation cost-effectiveness. The Commission found that both pre-program computer modeling and post-program productivity monitoring are valid efforts that MPC should pursue (FOF 582). The Commission also addressed the issue of "take backs." Take backs occur because the installation of conservation measures in a consumer's

residence causes the consumer's real income to increase, which leads to increased energy consumption. As a result, actual program savings can be less than pre-program projections (FOF 583). The Commission found that MPC should account for the effect of take backs in its cost-effectiveness analysis (FOF 586).

274. In this case MPC indicated that DSM program savings are derived from engineering estimates (i.e., pre-program projections) and that the effect of take backs is not included in the analysis (MPC Exh. 12, p. 5, MCC DR No. 224, PSC DR Nos. 19-20). MPC testified that it has not rejected the use of statistical models to evaluate its DSM programs. In 1993 MPC began an evaluation program using a combination of engineering models, pre- and post-statistical analyses, surveys, site visits and control group comparisons. MPC testified that this evaluation program will run through 1995.

275. In this docket the issue of DSM cost-effectiveness is related to MPC's request to rate base DSM investments. However, this issue is critically important to MPC's overall integrated least cost resource planning and acquisition process. The evidence in this case does not suggest that the Commission should disallow any of the DSM investment MPC is requesting to rate base, and no party has requested that the Commission disallow any of those investments. Parties have, however, expressed concern about the information available to judge whether these investments should be allowed. It is important, as the Commission recognized in Order No. 5360d, that MPC develop reliable information about the productivity of its DSM programs.

276. The Commission orders MPC to present the results of a completed evaluation in its 1995 least cost plan filing and its next rate case.

CONCLUSIONS OF LAW

1. The Applicant, Montana Power Company, furnishes electric and gas service for consumers in the State of Montana, and is a "public utility" under regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company's rates and

operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Sections 69-3-303, 69-3-104, MCA, and Title 2, chapter 4, MCA.

4. The rate level approved herein is just and reasonable. Sections 69-3-330 and 69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

1. Applicant, Montana Power Company, is hereby authorized an increase in annual Montana jurisdictional electric revenues of $7,595,458.

2. Applicant, Montana Power Company, is hereby authorized to implement increased rates, beginning on the effective date of this Order, designed to increase annual Montana jurisdictional electric revenues by $7,595,458. The increased rates shall be on a uniform percentage basis.

3. Applicant, Montana Power Company, is hereby ordered to rebate the excess electric revenues ordered in the Interim Order. The difference between this Order and the Interim Order amounts to $1,229,697 on an annual basis, and shall be rebated at an annual interest rate equal to 11.25 percent which is the return on equity granted in the Interim Order. The rebate shall be for the period between the effective date of the Interim Order and the effective date of this Order, and shall be amortized over a period equal to the period between the effective date of the Interim Order and the effective date of this Order. This rebate shall begin on the effective date of this Order.

4. Applicant, Montana Power Company, is hereby authorized an increase in annual natural gas revenues of $5,783,972.

5. Applicant, Montana Power Company, is hereby authorized to implement increased rates, beginning on the effective date of this Order, designed to increase annual natural gas revenues by $5,783,972. The increased rates shall be on a uniform percentage basis.

6. Applicant is hereby ordered to comply with any and all directives of the Commission as described in the body of this

Order.

7. The electric and natural gas revenue changes ordered by the Commission are in lieu of and not in addition to the interim changes authorized by previous Commission orders in this Docket.

8. The effective date of this Order is April 28, 1994.

DONE AND DATED this 25th day of April, 1994, by a 5 to 0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BOB ANDERSON, Chairman

BOB ROWE, Vice Chairman
(Dissenting concerning return on common equity, depreciation reserve adjustment, and nonconsumable materials)

DAVE FISHER, Commissioner

NANCY McCAFFREE, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Kathlene M. Anderson
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

OPINION OF COMMISSIONER ROWE

I concur in most parts of the Commission's order. The procedure followed in the case was sound and allowed for reasoned consideration of the issues presented. I dissent from three specific decisions:

1. Return on equity. I would have preferred a return on equity no greater than 10.5 percent, rather than 11 percent as approved by the Commission. This would have lowered the electric revenue requirement by approximately $3.6 million and the natural gas revenue requirement by approximately $900,000.
2. Depreciation reserve adjustment. With some misgivings, I would have adopted the Montana Consumer Counsel depreciation reserve adjustment, as proposed. This would have lowered the electric revenue requirement by approximately $6.5 million and the natural gas revenue requirement by approximately $1.5 million.
3. Nonconsumable materials. I would have denied MPC's proposed adjustment to nonconsumable materials and supplies associated with the Colstrip plants. This would have lowered the electric expense by $193,970.

This opinion expands on these three points of disagreement. It then explains my position on the demand-side management issues in the case. Finally, it offers several observations on matters of "regulatory reform" raised in this docket.

I. RATE OF RETURN ON COMMON EQUITY.

The Commission majority voted to authorize a return on common equity of 11 percent. I believe this is at least .5 percent too high.

Setting the rate of return is an area in which highly-complex financial analyses collide with the informed use of the decision-makers' judgment. Both MPC and MCC presented sophisticated "discounted cash flow" studies. After the Commission voted to reject MPC's proposed flotation adjustment, the range of probable outcomes was between MCC's recommendation of 10.25 percent and MPC's recommendation of 11.35 percent.

Regulators must use their discretion carefully. MPC witness Dr. Charles Olson agreed in questioning that Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989), stood for the propositions that a reviewing court's focus should be on the bottom line results of the regulators' decision, that there is a band of discretion within which rate of return decisions are constitutionally acceptable, and that regulators should not arbitrarily switch methods with an exclusively results-oriented approach. (Tr. pp. 426-431.)

The following factors support a 10.5 percent rate of return: (1) Dramatically falling capital costs, rendering MPC's initial and rebuttal requests untenable; (2) Greater internal consistency of the MCC study as opposed to the MPC study;[1] (3) MPC's inability to rebut effectively the MCC study;[2] (4) 10.5 percent was the high end of the range of possible returns considered reasonable by MCC witness Dr. Caroline Wilson; (5) Consumer testimony at public hearings was consistent with a lower rather than higher rate of return.

A side issue concerned MPC's claim that bond rating agencies perceive the Montana Public Service Commission as too "tough" on regulated utilities, and that therefore the Commission should grant a higher return. MPC argues that the perception of "regulatory risk" causes bond ratings agencies to lower their ratings for MPC, which drives up the price MPC must pay for capital and eventually forces MPC customer rates up. MPC believes that the Commission should raise customers' rates now to avoid having to raise them later because of lower bond ratings and higher capital costs.

There are a number of problems with MPC's position. First, it is impossible to sort out the effects of perceived regulatory risk on bond ratings from the effects of countless other factors. Other factors might include MPC's status as a single-state

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[1] E.g., MPC made inconsistent adjustments to its rebuttal case, changing yield numbers but not growth; MPC inconsistently used historical growth and market projections, relying heavily on market growth on the electric side but apparently not for gas; MPC listed IBES growth projection on the electric side but appears to have used them only for gas.

[2] MCC's restatement of one historical year's low numbers appeared to be a responsible application of the model, not a defect of the model.

electric utility; the overall condition of the Montana economy; changes in the electric industry; perceptions about past and current MPC management; actions by current MPC management; and, the continuing effect of past MPC decisions. MCC witness Wilson believed that MPC's current bond rating, though adequate, continues to be depressed below where it should be (given the soundness of current MPC management) as a result of the Colstrip project.

Second, making contested case decisions with a primary focus on the reaction of bond raters would risk insulating utility management from the consequences of its own actions. A primary justification for economic regulation is to impose on monopolies discipline similar to that imposed by competitive markets. Regulation based on bond ratings would be regulatory nihilism.

Third, bond ratings and utility regulation serve divergent interests. The concerns of investors and of utility customers are not the same, and may conflict.

Fourth, even assuming the Commission's decisions did directly and measurably affect bond ratings, the benefit to customers of lower rates sometime in the future would in most all cases be less than the cost to ratepayers in the present of higher rates now.[4]

The Commission should evaluate issues on their own merits, including proposals to modify general Commission rules and policies. While advancing the argument of "regulatory risk" MPC witness Cole agreed that a regulated environment continues to be generally less risky than a competitive environment. (Tr. pp. 408-9.) He also agreed that the Montana Commission has taken several steps which reduce so-called risk, such as approving the optional filing rules and adopting integrated least cost planning for electric utilities. (Tr. p. 409.) In sum, proposals in rate cases should be considered on their merits, taking into account those factors most directly relevant. Proposals to change regulatory rules and policies should be evaluated primarily upon

[4] MCC witness Wilson testifies that her studies indicated there was unlikely to be any reduction in return requirements subsequent to an upward revision to bond ratings, in part because equity costs do not appear to be significantly related to bond ratings. MCC3, p.6. Further, she noted that Montana's Value Line regulatory ranking was average, "indicating that the alleged lack of regard is not universal." Id. at 11.

whether they better meet the purposes of regulation, not on the anticipated reactions of third parties.

II. DEPRECIATION RESERVE ADJUSTMENT.

MPC's case was filed with a calculated year-end 1992 rate base. MCC witness Frank Buckley proposed adding an additional year's expenses for depreciation, amortization and depletion to the respective reserves ("depreciation reserve adjustment").[5] The Commission majority rejected this adjustment, but did adopt a smaller adjustment to accumulated depreciation proposed by MCC witness Al Clark. I dissent from the former, but concur in the latter as one part of an appropriate adjustment.

MCC argued that the depreciation reserve adjustment was a known and measurable change occurring within thirteen months of the close of the test year, the kind of adjustment commonly approved by the Commission. MPC responded in part that making the adjustment would result in a mismatch between rate base, revenues and expenses during the time rates would be in effect.

This is admittedly a close call. Based upon the pre-filed testimony alone, I was inclined to accept MPC's argument concerning alleged matching problems. Live testimony and briefs changed my mind.[6]

MPC's argument about matching is serious and gives real pause. The relevant considerations were not as well developed in MCC's initial testimony as they were in MCC briefs or even cross-examination. On balance, however, MPC's position was more a matter of asserting the mismatch than of reasoned analysis.

Among the considerations supporting the adjustment are the following. Under the optional filing rules, utilities are essentially allowed to bring rate base values forward six months (from an average historical year to a year-end figure). Depreciation associated with that plant is known and measurable

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[5] MCC first proposed this adjustment in a Mountain Water case, docket 92.4.19. I recused myself in that case. The commissioners participating ultimately decided not to approve the adjustment there, believing Mountain Water was not fully apprised of its implications, and instead deferred consideration to the present case. In making my decision in this case, I have confined myself to the pre-filed testimony, live examination, and briefs in this case. I have specifically refrained from considering the record in the previous Mountain Water case.

[6] I am concerned that both parties failed to cite or discuss any relevant casw law. For practical purposes, this is a case of first impression. A development of any relevant cases from jurisdictions, while not controlling, would have been valuable.

with certainty. The actual value of that specific plant will clearly be less during the time rates are in effect than at the end of the test year. Utility operating statements book the next year's depreciation, and these statements form the basis for virtually all financial analysis. Finally, allowing adjustments to the utility operating statement to reflect costs after the close of the test period while rejecting the proposed adjustment appears inconsistent.

The Commission considered and rejected several ways to adopt the reserve depreciation adjustment and address MPC's matching argument. The Commission wisely rejected allowing rate base additions for the full twelve months after close of the test year as too speculative. It also did not choose the option of updating plant additions through August 1993, based on actual additions. Either approach would have failed to address MCC's basic point, that the proposed depreciation adjustment is associated with plant in service at the close of the test year. (August or December, 1993, plant additions would have had additional depreciation associated with them.)

Given the difficulties with the two options just described, the Commission may have elected the second best choice. However, consistency now requires that the Commission attempt to better articulate its policy on post-test year adjustments, and abide by that policy.

III. NONCONSUMABLE MATERIALS CHARGED TO MATERIALS AND SUPPLIES.

The Commission erred in approving MPC's proposal to amortize original equipment replacement parts for the Colstrip plants over the remaining expected lives of those plants. Currently, these supplies are charged to a maintenance expense account as they are used. Not every argument raised by MCC in opposition to amortization was solid. However, the assumptions necessary to approve amortization are overly speculative.

The Colstrip plants are enormously capital-intensive, with generally good operating records. Experience with other generating resources suggests it is highly likely the Colstrip plants will remain in service after the end of their useful lives. If so, adopting the adjustment exacerbates rather than reduces inequity between ratepayers in different years. Further, it is unknown what quantity of parts will actually be used, or whether when Colstrip 1 is removed from service it might serve as a parts source for its twin unit. Given these unknowns, the prudent course would have been to continue expensing parts as they become needed, events which are known with certainty.

IV. DEMAND-SIDE MANAGEMENT.

Efficiency is smart. As a result of the "demand-side" conservation obtained over the past few years, many utility customers around the country are already living more comfortably, seeing smaller total bills, and avoiding the rate shock which would be caused by new central generating plants. Large industrial and commercial customers, potentially large sources of both conservation and cogeneration, may stand to benefit the most, as their overall business efficiency is improved.[7]

Over the past several years the Commission has approved measures designed to put demand-side resources on an equal footing with supply-side resources, and to recognize market barriers faced uniquely by demand-side resources. In this case, a unanimous Commission has approved a "decoupling experiment," agreed to by all parties but one, designed to prevent the utility from being harmed as a result of reducing its sales through conservation obtained between rate cases.[8]

The participants in the decoupling stipulation learned much from experience in other states. The decoupling mechanism is well-crafted to focus only on revenues lost through effective conservation. The stipulation also builds in safety valves to avoid risk shifting away from the utility and to monitor the "experiment."

Witnesses for the proponents demonstrated the first part of their analysis: That effective conservation programs will reduce utility revenue between rate cases. They did not and perhaps

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[7] It should be noted that there may be risks associated with too great a utility investment in DSM activities by large customers which might leave the system. In docket 93.7.29 (the pending MPC cost of service and rate design case), MPC witness Pat Corcoran discussed the DSM potential of RP Chem. He stated that it could be risky to invest in a load which might leave the system within several years. (Docket 93.7.29, tr.pp.479-480.)

[8] At the time of a rate case, the clock is essentially reset. Therefore, the more frequent rate cases occur, the less the harm from lost sales between rate cases.

could not empirically demonstrate that as a result utilities in the real world do a less effective job developing the conservation resource.[9]

Proponents did not adequately explain what was meant by the term "experiment," or how results are to be measured. There is no control group, so decoupling is an experiment primarily in that both primary results and secondary effects will be monitored and the Commission reserves the right to pull the plug. The parties did not agree on whether decoupling would be a success if MPC's existing program, currently being ramped up, stayed on course or only if that program is expanded.[10]

For my part, I expect to see aggressive and efficient pursuit of the conservation resource. The amount of money expended (the measure focused on in the stipulation) is at best an initial indicator. MPC needs to move beyond engineering estimates of success, to statistically document results.

At the same time, demand-side management is an area where creative insights have often produced big results. One message from approval of the stipulation is that MPC should encourage its people to apply their intellectual resources to meeting MPC customers' energy needs on the demand-side as well as the supply-side.

"But for" is the ultimate measure: Are total resource costs lower than they would be but for the demand-side programs? Are customer bills lower than they would be but for demand-side programs? With thoughtfulness, creativity, and diligence, the answer should be "yes."

V. REGULATORY REFORM.

Several themes sounded throughout this proceeding. These included MPC's position that the regulatory compact, which entitles it the opportunity to earn a fair rate of return, needs attention; and, that incentives must be better aligned with the actions desired.

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[9] On an ad hoc level, it seems clear that utilities in states which have adopted some form of decoupling do undertake much more aggressive conservation programs. It is unclear the extent to which this validates the theory of decoupling, or whether it is an example of the "Hawthorn effect" (it's not as important what you do as that you do something). Some might suggest the answer is, "Who cares as long as it works."

[10] This raised the interesting question of whether there exist cost-effective demand-side resources which do not appear in the MPC least cost plan. The parties had a number of responses.

The utility community actively pursued modification of the regulatory compact through adoption of the "optional rules," with a choice between an average historical test year and a year-end test year. Although not serving as Commissioners at the time the optional rules were adopted, we three new Commissioners in this Order had to resolve issues directly or indirectly raised by those rules (e.g., actual year-end customer count versus "shaping" the customer account by month).

Declining cost utilities (many telephone companies) might be expected to remain with the traditional average test year. Increasing cost utilities (many electric utilities) will more likely elect the year-end option. In this case, MPC's initial filing was substantially higher under the optional rules than it would have been under the traditional average test year.

One part of the optional rules is an obligation that revenue requirements cases be filed every two years. For electric utilities, revenue requirements cases, rate design cases, and least cost plan filings are now coordinated. On the whole, this coordination is working well.

During this case, MPC suggested that its stated inability to earn a fair return on its investment may lead it to file annual revenue requirements cases.[11] Annual filings might smooth rate changes and better match current rates to current costs.

Annual filings have serious drawbacks as well, which need to be addressed. Annual filings would impose tremendous burdens on Commission and Consumer Counsel staff (and less so on the utility). Ultimately, staff and consultant time costs money to Montana ratepayers. Given scarce resources, annual MPC filings would detract from the scrutiny which could be given the issues in an MPC case and would force the Commission and Consumer Counsel to shift resources away from other cases and from other matters of great concern to ratepayers (a range of telecommunications issues, for example). The customers would lose.

There may be some relationship between annual filings and

[11] In an example of very poor timing, MPC held a press conference while this case was under deliberation, announcing it was considering annual filings due to claimed failure to earn its return. The press conference was reported uncritically and carried prominently in most daily papers.

Commission policy on interim rate requests. The Commission has indicated interest in reviewing its policy on interims. There would be much less justification for granting interims were revenue requirements cases filed annually.

This case concerned several kinds of "incentive regulation." An incentive is "something that incites or has a tendency to incite to determination or action." (Websters) All regulation, positive or negative, creates incentives, intentionally or not. In this case, the Commission acted cautiously to remove a perceived negative incentive to demand-side management, but declined to adopt additional positive incentives at this time.

While we consider discrete incentives and procedural changes, tweaking the regulatory system, debate proceeds concerning the best general course in a potentially-changing environment. This important discussion will be carried on in contested cases and in non-adversarial forums. The foregoing comments are intended not to foreclose the discussion, but to engage it.

RESPECTFULLY SUBMITTED this 22nd day of April, 1994.

BOB ROWE
Vice Chair

Service Date: May 3, 1994

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER Of The Application Of The MONTANA POWER COMPANY For Authority To Increase Rates For Natural Gas And Electric Service.	UTILITY DIVISION DOCKET No. 93.6.24 ORDER No. 5709d (REVENUE REQUIREMENT)

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ERRATA TO FINAL ORDER

Attached is a replacement page 70. The original page contained a error – the last line of FOF 208 said "MPC" and should have said "the Company." Please discard the original page 70 and insert this corrected page.

captive coal methodology is overstated in this Docket. MPC failed to include earnings, which is inappropriate. More importantly, WECO's financial statements show that the Company has more than sufficient assets to pay all of its liabilities.

209. In rebuttal Mr. Pederson noted that the pro forma portion of the adjustment is calculated by applying the change in the Consumer Price Index to certain contract factors in the coal contracts, multiplied by the number of tons of coal in the test period. The contract for purchases of coal at the Corette Plant no longer includes this contract factor. The pro forma piece of the captive coal adjustment totals $75,821, of which the Corette portion is $15,474. During the hearing staff asked Mr. Kirby about this issue:

> Q. The contract for purchases of coal at the Corette plant no longer includes this contract factor. Mr. Pederson identifies the Corette portion of the calculation to be $15,474. Do you agree that the captive coal adjustment should be reduced by that amount?
>
> A. It should be made consistent with the Company's contracts and how the coal expense is treated in the rate case as a whole, but I have not attempted to calculate exactly what that number would be. I'm not aware that there is anything wrong with his figure. (Tr. p. 666)

The Commission finds that the captive coal adjustment should be reduced by $15,474 pursuant to the rebuttal testimony of Mr. Pederson and the cross-examination of Mr. Kirby at the hearing.

210. At the hearing staff questioned Mr. Pederson on his interpretation of how Pacificorp (PP&L) recently treated some of its coal operations. Specifically, PP&L approved a transfer of Bridger and Glenrock coal mining properties into the Company's electric utility operations. He testified that MPC has not planned to do the same, although he admitted that MPC wondered whether it should consider doing so. He stated that he could not understand how one could figure out how a coal mine that sells 80 percent of the coal outside the utility could allocate some

portion to the utility. He believed, therefore, that it would not be a "correct thing for [MPC] to consider," but would be open to a presentation that would make sense. (Tr. pp. 558-559) Dr. Landon also made it sound as though cost allocations for the coal mining operations would be so complex as to be beyond the limits of possibility.

211. Dr. Wilson addressed the allocation of coal sales during his cross-examination. He testified that there was not a difficult allocation problem. WECO basically has undivided interests in a coal supply which can be allocated on a straightforward percentage basis. He recommended that the Commission recognize the pro rata share attributable to MPC's purchases from the coal mine, determine the profitability attributable to that purchase/sale, and then decide the rate of return appropriate for the transaction, for ratemaking purposes. (Tr. pp. 642-644) The Commission agrees with Dr. Wilson that allocations related to WECO for sales made to MPC are the types of allocations made routinely in regulation. The Commission does not agree with Mr. Pederson on the issue of allocating costs between coal supplied by WECO to MPC and coal sold by WECO to other third parties. Cost allocations are a standard part of utility ratemaking.

Commission Decision

212. The methodology of the captive coal adjustment in this case is identical to that used in the last case. The adjustment is over two times greater than in the last case, primarily as a result of the reorganization of WECO. Another factor